Service Date: December 16, 2005

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA PSC
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| IN THE MATTER of the Application of NorthWestern Energy's Electric Default Supply Tracker Filing | ) ) ) | UTILITY DIVISION DOCKET NO. D2003.6.77 ORDER NO. 6496f |
| IN THE MATTER of the Application of NorthWestern Energy's Electric Default Supply Tracker Filing | ) ) ) | UTILITY DIVSION DOCKET NO. D2004.6.90 ORDER NO. 6574e |

# FINAL ORDER

## Appearances

FOR THE APPLICANT:

*NorthWestern Energy*

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BEFORE:

GREG JERGESON, Chairman
BRAD MOLNAR, Vice-Chairman
DOUG MOOD, Commissioner
ROBERT H. RANEY, Commissioner
THOMAS J. SCHNEIDER, Commissioner

COMMISSION STAFF:

Al Brogan, Staff Attorney
Leroy Beeby, Rate Analyst
Eric N. Eck, Chief of Revenue Requirements
Will Rosquist, Staff Economist

**Procedural History**

1. On June 16, 2003, NorthWestern Energy (NWE) filed its first electric default supply tracker filing with the Montana Public Service Commission (Commission). NWE filed this application late. In Docket No. D2001.10.144, Order No. 6382d, the Commission stated: "A filing for approval of interim rates to recover electricity supply costs for the period July 1, 2003 through June 30, 2004 must be made no later than June 1, 2003." NWE made an allowance for the late filing by requesting that interim rates be effective for service on and after July 15, 2003. The filing contained the following elements: 1) the electric supply deferred cost account balance as of June 30, 2003 and the projected electric supply cost for the twelve month period July 1, 2003 through June 30, 2004, and 2) a request to change the electric cost adjustment from annual to monthly. The Commission issued a notice of the filing on June 23, 2003. On July 17, 2003, the Commission issued Interim Order 6496a granting interim rate relief to NWE effective for service on and after July 15, 2003. The Commission voted to authorize the Interim Order on July 15, 2003 by a 5-0 vote,

2. On June 7, 2004, NorthWestern Energy (NWE) filed its electric default supply tracker filing with the Montana Public Service Commission (Commission). NWE filed this application late for the second time in two years. The Commission again reminded NWE that annual electric default supply tracker filings must be filed no less than 30 days prior to the proposed effective date of the rate change (which is normally July 1st). The filing contained the following elements: 1) the electric supply deferred cost account balance for the 24-month period ending June 30, 2004 and the projected electric load, supply and related costs for the twelve month period July 1, 2004 through June 30, 2005; 2) a request to continue the monthly electric tracker; 3) a request for authority to recover costs and corresponding lost revenues associated with Demand Side Management (DSM); 4) a request to recover costs associated with the Tiber Montana Hydro Project and the Thompson River Co-Gen LLC project; and 5) a request to include the Public Service Commission (PSC) and Montana Consumer Counsel (MCC) fees in the electric default supply cost. The Commission issued a notice of the application on July 19, 2004. On July 28, 2004, the Commission issued Interim Order No. 6574 granting interim rate relief for service effective on and after August 1, 2004. The Commission authorized the Interim Order on July 20, 2004 by a vote of 3-2.

3. On September 20, 2004, Procedural Order No. 6574b in Docket D2004.6.90 and Procedural Order No. 6496d in Docket No. D2003.6.77 each stated that Docket D2004.6.90 and D2003.6.77 would be jointly administered. In Order No. 6574b, the Commission identified additional issues for consideration in this Docket. Those issues included public policy issues related to the allocation of NWE's Universal Systems Benefit (USB) funds, and the reasonableness of the current allocation of NWE-collected USB funds among qualifying categories: local conservation, low-income weatherization, renewable resource projects and applications, research and development, market transformation and low-income energy assistance. AARP in its June 3, 2004 comments in Docket No. N2004.1.15 and again in a letter dated August 2, 2004 requested the Commission initiate a proceeding to consider, in a public forum, NWE's demand-side resource acquisition plans and budgets and their effect on USB programs. AARP also recommended that the Commission more closely supervise USB programs and expenses for all regulated electric and gas utilities. In its June 3, 2004 written comments in Docket No. N2004.1.15, AARP also suggested the Commission consider alternatives to monthly default supply rate adjustments and recommended that NWE capitalize investments in demand-side resources when those resources have expected lives longer than one year.

4. On December 14, 2004, at the request of NWE, the Commission suspended the Procedural Order in the Dockets. On December 16, 2004 NWE, MCC, Montana Office of Northwest Power and Conservation Council, District XI of the Human Resource Council, Renewable Northwest Project, Natural Resources Defense Council and AARP moved the Commission for an order approving a stipulation among them. On December 23, 2004, the Commission issued Proposed Order No. 6574c in Docket D2004.6.90 approving the stipulation which transferred, on a one-time basis, $621,274 from year 2005 USB conservation and market transformation programs to low-income discount for both electric and gas customers of NWE, and removed consideration of issues related to USB from these dockets. The Commission authorized the Proposed Order on December 21, 2004 by a vote of 5 to 0.

5. On May 6, 2005, the Procedural Orders in these dockets were revised and reissued as Order No. 6574b in Docket D2004.6.90 and Order No. 6496e in Docket D2003.6.77.

6. On June 7, 2005, the Commission denied Petitions of Intervention from Energy Share of Montana and Rocky Mountain Development Council. The Commission issued Notices

of Commission Action memorializing the denials on June 9, 2005. Both of the petitions stated an interest related to NWE's collection and use of USB funds. The petitions were denied on the basis that the issues identified by the petitioners as areas of interest were not relevant in these dockets. A public hearing was held on September 7, 2005.

## Summary of the Testimony

**Prefiled Testimony Docket D2003.6.77**

**NorthWestern Energy**

**Kevin J. Markovich**

7. Mr. Markovich addressed the following topics: 1) the actual results of the 2002/2003 default supply tracking period; and 2) the forecasted electric load, resources and costs for the 2003/2004 default supply tracking period.

**2002/2003 Default Supply Tracking Period**

8. Exhibit__(KJM-1) showed actual information for the period July 2002 through April 2003 and revised estimates for May and June 2003. NWE expected to purchase 5,182,112 megawatt hours (MWh) of energy with a total cost of $177,117,542. Actual default supply costs were less than the original estimates in the June 2002 filing, resulting in an over collection of $593,932.

9. Actual default supply energy costs and volumes were very close to those forecasted in the June 2002 tracker filing. Total MWh purchased were just 788 less than the 5,182,900 estimated in June 2002. Total energy supply costs were $826,863 less than the $172 million originally forecasted, a differential of less than one half of one percent. Total short-term transactions to meet load were within $260,000 of original projections.

10. Three basic components make up electric default supply portfolio costs for the 2003/2004 tracking period: 1) electric supply, 2) transmission services and 3) administrative support.

11. Electric supply in the 2002/2003 tracker consisted of: a) a 300 Megawatt (MW) firm base load contract with PPL Montana that is supplied 24 hours a day, seven days per week through June 30, 2007; b) a 150 MW heavy load, unit contingent contract with PPL Montana that supplies energy from 8:00 am to 11:00 pm Monday through Saturday through June 30, 2007;

c) a 111 MW unit contingent contract with Duke Energy, which expired on June 30, 2003; d) approximately 100 MW of unit contingent Qualifying Facility (QF) energy (only the "in market" portion of these contracts, $32.75 per MWh is charged to electric default supply); e) a very small amount of energy from Milltown dam priced at $32.75 per MWh; f) short-term power purchases and sales with various suppliers in which NWE either buys or sells energy in the spot market to match electricity supply with customer demand; and g) system imbalance adjustments, operating reserves and real-time transactions, which are hourly energy purchases or sales to maintain supply and demand balance on the electric transmission and distribution system for reliability purposes. According to Mr. Markovich, the PPL Montana and Duke Energy contracts were a result of a competitive Request for Proposals (RFP) and were previously reviewed and approved by the Montana PSC.

12. Transmission services are costs associated with moving electricity from one location to another and for other services, generally referred to as "ancillary services," which are required to maintain transmission system integrity and reliability. Costs to move power to default supply customers over the transmission and distribution systems are included in delivery rates and as such, no additional revenue is collected for these costs in the tracker. Regulation and Frequency Response Service, generally referred to as "load following," is an ancillary service that is required to be purchased yet it is not included in delivery rates and hence, these costs are included in the tracker.

13. Administrative support includes incremental administrative and general costs of $1,805,271 in default supply costs. These costs include outside legal, scheduling, software, broker costs and other incremental expenses directly related to the electric default supply function (such as Lands Energy Consultant Services). Administrative expenses were higher than originally estimated due to costs associated with the initial year of default supply operations and the cost of conducting two RFPs. These costs do not contain any expenses for internal company personnel.

14. The QF portion of the default supply consists of three large unit contingent resources and multiple smaller resources. Broadwater Dam is a 6-10 MW run-of-river hydro facility. Billings Generation Incorporated (BGI) (55 MW) and Colstrip Energy Limited Partnership (CELP) (35 MW) are base load thermal units.

15. During the 2002/2003 tracking period CELP was offline for nearly six months and BGI was offline for nearly three months, requiring NWE to make replacement purchases from the market. The Tier II settlement in Docket No. D97.7.90 requires NWE to provide default supply customers with a minimum of 809,002 MWh of energy at $32.75 per MWh from either the QF contracts or the market.

16. NWE purchased 1,765,755 MWh and sold 1,512,759 MWh of energy in either short-term purchases (less than 90 days), or through day ahead and hour ahead scheduling. Purchases included 135,475 MWh of imbalance energy. Load following costs were $1,977,439 for the 2002/2003 tracking period, reflecting default supply's proportionate share of the overall costs for load following on the NWE transmission system.

17. The actual results for the 2002/2003 tracking period were revenues of $168,939,163 and energy supply costs of $177,117,542. These elements resulted in an under-collection of $8,178,379.

**2003/2004 Default Supply Tracking Period (Forecasted)**

18. Total billed sales were estimated to be 5,478,183 MWh. However, NWE must purchase more electricity than it sells due to transmission line losses of approximately eight percent. The line losses for each class were based on information from Docket No. D97.7.90. Additionally, billed sales were adjusted through a cycle billing adjustment to shift the billed energy to the calendar month in which it was actually delivered. NWE estimated that it would need to procure 5,912,351 MWh. There was substantially more load in 2003/2004 than NWE previously planned due to the return of a number of choice customers to default supply service. Forecasts indicated that an additional 546,620 MWh of energy was needed to serve the returning choice customers.

19. The return of choice customers to default supply was estimated to affect default supply customers in two ways. First, the default supply portfolio of resources was not large enough to serve the additional load so incremental market purchases needed to be made. The additional market purchases were forecasted to be more expensive than the average cost of NWE's procured resources, which would increase the blended commodity rate to default supply customers by approximately $0.35 per MWh. That increase would be offset by approximately $0.17 per MWh due to the returning choice customers sharing in the cost of the 2002/2003 under

collection of $8.17 million. The net effect to existing default supply customers of the returning choice customers would be an increase of $0.18 per MWh, or approximately $900,000 for the 2003/2004 tracking period.

20. NWE indicated that it would procure electricity in 2003/2004 from the two PPL Montana contracts as well as the unit contingent QF resources. The Duke Energy contract was set to expire on June 30, 2003. Net short-term transactions were projected to be 29 percent (1,734,333 MWh) of the total resources needed to meet the default supply load, representing exposure to price fluctuations. Of this total, 32 percent is due to returning choice customers, 30 percent is due to the expiration of the Duke Energy purchase contract, and similar to last year 38 percent of the total short-term transactions are needed to shape long-term purchases to fit the load. This reliance on short-term purchases results in a fairly high degree of risk, according to Mr. Markovich.

21. The projected unit cost of electricity was $40.87 including losses. This was an increase of approximately 11 percent over the energy rate in the 2002/2003 tracking period. An additional $1.64 per MWh cost was included to recover the net under-collection from the 2002/2003 tracking period, making a projected total supply-related unit cost of $42.51 per MWh. Supply costs were projected to be $221,960,551 the deferred account was $8,178,379 and revenues were projected at $230,138,930 for the 2003/2004 tracking period.

**Cheryl A. Hansen**

22. Ms. Hansen's testimony dealt with five subjects: 1) the Company's proposal to adjust electric supply costs on a monthly basis; 2) an explanation of the derivation of the 2003/2004 billing statistics; 3) an explanation of the impact of the tracker startup on the deferred supply cost balance; 4) the derivation of the proposed deferred supply cost rates resulting from the over/under collection in the 2002/2003 tracking period and 5) the derivation of the proposed default supply rates for the forecasted 2003/2004 tracking period.

**Monthly Electric Supply Cost Rate Changes**

23. NWE requested electric default supply rates be adjusted monthly to allow a more timely reflection of supply cost changes in rates. The monthly rate change would be based on

the most recent 12-month forecast of annual supply costs divided by the most recent 12-month forecasted load.

24. The primary goal of monthly electric default supply trackers is to ensure that customer's rates more immediately reflect the actual cost of electric supply, both increases and decreases, which will result in more accurate price signals. Monthly rate changes will help reduce the balance in the deferred account, which reduces the level of interest cost on the deferred balance. Monthly cost adjustments provide the best match of cash receipts to expenses. A similar proposal was included in the recently filed gas cost tracker filing and is a concept also used by other utilities in Montana. The first monthly tracker was expected occur on September 1, 2003.

**2003/2004 Tracker Year Billing Statistics**

25. NWE used historical actual billing data, adjusted for weather, known changes and forecasted loads to derive the billed usage for the July 2003 to June 2004 tracking period

26. Ms. Hansen explained the difference between cyclical and calendar usage (sales). Cyclical usage represents customer usage billed throughout a calendar month on each of twenty-one billing cycles. Each billing cycle covers approximately 30 days of metered usage. Calendar usage on the other hand, represents a customer's adjusted usage as if it were recorded for a calendar month. Calendar data is used to determine the cost of energy supply, which is incurred on a calendar basis and is used by Mr. Markovich in his analysis. Cyclical data is used to establish rates for billing purposes.

27. At pages 4-7 of her testimony Ms. Hansen provided a detailed explanation of Tables 1-7 of Exhibit__(CAH-1).

28. Costs associated with serving Yellowstone Park are recovered through a separately negotiated contract rate. As a result, this load and its revenues are excluded from any rate design for MPSC jurisdictional rates.

**Tracking Startup Deferred Balance**

29. The implementation of the electric default supply rates for service on and after July 1, 2002 resulted in an under recovery of $8,772,311 for the month of July 2002. This under recovered amount was directly attributable to the startup of the new electric default supply

tracker. When electric default supply rates were initiated for service on and after July 1, 2002 approximately one-half of the July metered usage was actually billed at the new electric default supply rates. This is because of NWE's cycle billing and proration process. (Cycle billing results in NWE billing its customers on twenty-one different days in each calendar month. In a month when a new rate is implemented, each bill is prorated, meaning only a portion of the days in that month are actually billed at the new rate. Therefore, on average, the initiation of the new electric default supply rates resulted in only one-half of new default supply revenues for July 2002 as compared to a full month of actual new electric supply costs.)

30. Comparing actual new electric default supply costs for July 2002 of $15,654,591 to actual electric default supply revenues for July of $6,882,280 produced an under recovery of $8,772,311. Ms. Hansen prepared Exhibit__(CAH-3) which demonstrated what actually occurred in July 2002. While that exhibit does show a full month of usage and revenues billed for July 2002, only that portion of the revenues associated with usage and rates on and after July 1st is applicable under the new Commission authorized electric default supply tracker. The revenues for usage prior to July 1st cover costs related to power purchased under the "buy-back" contract with PPL Montana, which expired on June 30, 2002.

**Derivation of Deferred Supply Rates**

31. The monthly deferred account balance for the twelve-month period ending June 2003 is a net under collection of $8,178,376. The net consists of the startup deferred under collected amount of $8,772,311 offset by the over collected amount of ($593,935). This is the amount NWE proposed for amortization in this docket. NWE proposed separate rates to recover the electric deferred account balance. The details showing the derivation of the proposed rates was set forth in Exhibit__(CAH-4).

**Derivation of Default Supply Cost Rates**

32. The total proposed electric default supply costs of $221,960,554 were used as a starting point. This figure was then reduced for the portion of July and August revenues billed at the current default supply rate ($.036841/kWh) and for electric supply revenues received from Yellowstone National Park (YNP). This produced remaining default supply costs of

$204,142,908 which were used for default supply rate design purposes in order to ensure that the total default supply costs of $221,960,554 were recovered by June 30, 2004.

**Prefiled Testimony – Docket No. D2004.6.90**

**NorthWestern Energy**

**Kevin J. Markovich**

33. Mr. Markovich addressed the following topics: 1) a recap of the 2002/2003 default supply tracking period; 2) nine months of actual results and three months of estimates for the 2003/2004 default supply tracking period and 3) the forecasted electric load, resources and costs for the 2004/2005 default supply tracking period.

**2002/2003 Default Supply Tracking Period**

34. Mr. Markovich provided the status of the initial 2002/2003 electric default supply filing. The Commission approved Interim Order No. 6494a in Docket No. D2003.6.77 on July 15, 2003, which set the deferred account balance for the 2002/2003 tracking period at zero pending a final determination in that docket. However, due to NWE's bankruptcy, the docket was suspended and has not been completed. Monthly electric supply cost tracking rate adjustments have been implemented each month since September 1, 2003.

35. In NWE's initial 2003 annual tracking filing, the proposed deferred account balance was $8,178,379 for the twelve-month tracking period. This included an under recovery of $8,772,311 for the month of July 2002. The implementation of the electric default supply rates for service on and after July 1, 2002 only reflected one-half of the month of July 2002 revenue, resulting in the July cost under recovery. The Company determined that its initial presentation in Docket No. D2003.6.77 should have included a full month of July 2002 supply revenues. That determination by NWE affected the deferred account balance presented in Docket No. D2004.6.90. The 2002/2003 deferred account balance as of June 2003 was reduced by $2,485,402 to arrive at the adjusted balance of $5,692,977. This balance was carried forward as the deferred account starting balance for July 2003. Adjustments for monthly over and under collections were made to this account during the twelve-month tracking period ending June 2004, resulting in a final deferred account balance of $738,167 as of June 2004.

**2003/2004 Default Supply Tracking Period**

36. Mr. Markovich presented the results of the 2003/2004 default supply tracking period in Exhibit__(KJM-2). The exhibit showed actual results for the period July 2003 through March 2004 and updated estimates for April, May and June 2004. NWE expected to purchase 5,732,081 MWhs of energy at a cost of $197,696,388. In addition NWE expected to incur $3,717,471 of transmission, administrative and general (A&G), and interest costs to calculate total default supply costs of $201,413,859.

37. Actual supply volumes were very close to those forecasted in the first tracker filing in July 2003. In July 2003, NWE expected to purchase 5,735,219 MWhs to meet load; in the second tracker filing in July 2004, NWE expected to purchase 5,732,081 MWhs (which included 8 percent losses). Energy supply costs in the second tracker were expected to be $197,696,388 compared to the estimate in the July 2003 tracker filing of $210,246,646. The reduction was a result of two items: 1) active monitoring of the default supply load, including its sensitivities to weather and 2) constant analysis of both favorable and unfavorable market opportunities as they relate to prices, transmission outages and other operational events throughout the region that affect short-term market prices.

38. For the period of July 2003 through March 2004, including estimates for April, May and June 2004, default supply revenues were anticipated to be $206,368,669 resulting in an estimated over-collection for the period of $4,954,810.

39. There are three basic cost components that make up the electric default supply portfolio for the 2003/2004 tracking period: 1) electric supply, 2) transmission services and 3) administrative support.

40. Electric supply in the 2003/2004 tracker is made up of the following pieces: a) a 300 megawatt (MW) firm base load contract with PPL Montana that is supplied 24 hours a day, seven days per week. This contract expires June 30, 2007; b) a 150 MW heavy load, unit contingent contract with PPL Montana that supplies energy from 8:00 am to 11:00 pm Monday through Saturday. This contract expires June 30, 2007; c) approximately 100 MW of unit contingent Qualifying Facility (QF) energy. Only the "in market" portion of these contracts, $32.75 per MWh, is charged to electric default supply; d) short-term power purchases and sales with various suppliers in which NWE either buys or sells energy in the spot market to match electricity supply with customer demand. During the 2003/2004 default supply tracking period,

the net shortfall was approximately 1,555,880 MWhs (or approximately 27 percent of the annual requirements) and e) system imbalance adjustments, operating reserves and real-time transactions, which are hourly energy purchases or sales to maintain supply and demand balance on the electric transmission and distribution system for reliability purposes.

41. The PPL Montana contracts were a result of a competitive Request for Proposals (RFP) and were previously reviewed and approved by the Montana PSC.

42. Transmission services are costs associated with moving electricity from one location to another and for other services, generally referred to as "ancillary services," which are required to maintain transmission system integrity and reliability. Costs to move power to default supply customers over the transmission and distribution systems are included in delivery rates; therefore, no additional revenue is collected for these costs in the tracker. Regulation and Frequency Response Service, generally referred to as "load following," is an ancillary service which provides instantaneous voltage and energy regulation to balance load and resources. This service is currently provided by NWE's Transmission department and represents $1,660,500 of the $2,109,766 transmission cost.

43. Administrative support includes incremental administrative and general costs of $1,238,856. These costs include outside legal, scheduling, software, broker costs and other incremental expenses directly related to the electric default supply function (such as Lands Energy). Administrative expenses are approximately $100,000 lower than originally estimated in the July 2003 tracker filing and do not contain any expenses for internal company personnel.

44. Mr. Markovich testified that NWE procured and administered electric default supply contracts prudently during the 2003/2004 tracking period, as evidenced by the following: a) NWE scheduled and paid for the 300 MW of base load firm energy from PPL Montana every hour during the 2003/2004 tracking period; b) during all hours in which energy from the PPL Montana unit contingent contract was made available, NWE scheduled, received and paid for the energy (availability of the unit contingent contract was very close to what was expected - NWE's original forecast was 736,800 MWh and it expected to receive 739,200 MWh); c) during all hours in which supply from these resources exceeded load, NWE, like any utility, was required to balance the system and successfully re-marketed the energy at prevailing market rates, sometimes for a profit, sometimes at a loss, however, none of the energy from these contracts was foregone due to transmission constraints or as a result of operating or scheduling errors

within NWE's control; d) at all times NWE purchased and made available the necessary operating reserves needed for unit contingent contracts; and e) NWE successfully worked with power suppliers to implement acceptable credit and collateral arrangements per the terms of the contracts, which was a significant step in maintaining access to the market. NWE ensured that proper credit and counter-party relationships were available for day-to-day activities as well as emergency contingencies.

45. The QF portion of the default supply consists of three large unit contingent resources and multiple smaller resources. Broadwater Dam is a 6-10 MW run-of-river hydro facility. Billings Generation Incorporated (BGI) (55 MW) and Colstrip Energy Limited Partnership (CELP) (35 MW) are base load thermal units.

46. Pursuant to a Stipulation reached in Docket Nos. D97.7.90 and D2001.1.5, NWE must schedule energy from QF's to serve the default supply load at prices specified in Appendix D to the Stipulation. In the 2003/2004 tracking year NWE was responsible for QF deliveries to the default supply of 809,002 MWh at $32.75/MWh. NWE must provide replacement energy for any QF shortfall under the 809,002 MWh. Actual QF production for the 2003/2004 tracking period was expected to be 690,000 MWh. When unit contingent resources are not available, NWE uses a combination of term market purchases, day-ahead and same-day purchases to make up any deficiencies. As outage information, schedules and expected plant return dates are made available, the information is input into NWE's forecasting models to determine the best mix of resources needed to replace the unit contingent energy. Term purchases are often made at the Mid-Columbia trading hub. When energy is needed to serve load, it is either moved back to Montana or exchanged for Montana production. When the replacement energy is not needed, it is resold at Mid-Columbia, maximizing the value received. This process is used to minimize necessary short-term costs, including transmission, and to effectively meet fluctuations in loads.

47. In the 2003/2004 tracking period NWE purchased a net 1,556,179 MWh of short-term (less than 90 days) energy (short-term transactions plus or minus imbalance energy).

48. Mr. Markovich explained that purchases from Duke Energy do not appear in the 2003/2004 tracker filing because Duke and NWE were unable to agree on an extension of the one-year, 111 MW contract initially executed in 2002. In the spring of 2003 NWE and Duke met several times but were unable to agree to a price. Still, on many occasions throughout the

year NWE purchased energy from Duke at each day's prevailing market price. These purchases were included with other short-term transactions.

49. Load following costs were $1,660,500 for the 2003/2004 tracking period. Transmission costs for excess-energy sales amounted to $449,266 during the 2003/2004 tracking period. Wheeling costs were $1.1 million less in 2003/2004 than in 2002/2003. In the earlier tracking period the Duke contract provided power when the default supply did not need it. That meant that NWE had to incur transmission cost to move the excess energy to other markets. In 2003/2004 the default supply was deficit in almost all hours and short-term procurement was more efficiently matched to load requirements.

50. The actual results for the 2003/2004 tracking period were revenues of $206,368.669 and energy supply costs of $201,413,859. These elements resulted in an over-collection of $4,954,810.

**2004/2005 Default Supply Tracking Period (Forecasted)**

51. Total billed sales were estimated to be 5,778,906 MWh, including line losses and adjustments for cycle-billing. The projected sales for 2004/2005 were 23,452 MWh less than in 2003/2004.

52. NWE indicated that it would procure electricity in 2004/2005 from the two PPL Montana contracts as well as the unit contingent QF resources, 102,960 MWh from the Thompson River Co-Gen project, and 18,120 MWh from Tiber Dam. The rest of the supply was expected to be procured in the short-term market. DSM was expected to produce a 1,533 MWh reduction in expected load. Net short-term transactions were projected to be 26 percent (1,489,224 MWh) of the total resources needed to meet the default supply load.

53. The projected unit cost of electricity was $40.57 including losses. This was an increase of approximately 8 percent over the energy rate in the 2003/2004 tracking period. An additional $.14 per MWh cost was included to recover the net under-collection from the 2002/2003 and 2003/2004 tracking periods, making a projected total supply-related unit cost of $40.71 per MWh. In July 2003, NWE projected the following twelve-month cost to be $40.52 per MWh, while the actual cost for that twelve-month period turned out to be only $37.64 per MWh.

54. Revenues and energy supply costs were both projected at $218,030,103 for the 2004/2005 tracking period.

**Cheryl A. Hansen**

55. Ms. Hansen's testimony dealt with four subjects: 1) the derivation of the 2004/2005 billing statistics; 2) the deferred supply cost balance of the electric default supply tracker startup for the 2002/2003 tracking period; 3) the derivation of proposed deferred supply rates resulting form the over/under collection reflected in the 2003/2004 tracker and 4) the derivation of proposed default supply rates for the forecasted 2004/2005 tracker period.

**2004/2005 Tracking Period Billing Statistics**

56. As with the tracker filed in 2003. Ms. Hansen explained the difference between cyclical and calendar usage (sales), provided a detailed explanation of Tables 1-7 of Exhibit__(CAH-1) and explained that costs associated with serving Yellowstone Park are recovered through a separately negotiated contract rate.

**Tracking Deferred Balance**

57. The PSC first authorized electric default supply rates under the new electric default supply tracker for service on and after July 1, 2002. The July 2003 filing, only reflected one-half of a month of July 2002 supply revenue reporting an under recovery for the month of $8,772,311. Upon further review, NWE determined that the filing should have included a full month's worth of July 2002 supply revenues. Replacing the partial month with a full month of supply revenue reduced the under recovered deferred cost. The 2002/2003 tracking period under recovered ending balance of $8,178,379 in the July 2003 filing was replaced with the adjusted under recovered ending balance of $5,692,977. This amount then becomes the deferred account beginning balance for the 2003/2004 tracking period.

**Derivation of Deferred Supply Rates**

58. The deferred account for the 12 months ended June 2003 was an under collection of $5,692,977. For the 12 months ended June 2004 the deferred account balance was an over

collection of $4,954,810. The net of these two years in the deferred account is an under collection of $738,167. This amount was proposed by NWE for amortization in this filing.

**Derivation of Default Supply Rates**

59. The filing contained total proposed electric default supply costs of $217,291,936. After elimination of the Yellowstone Park revenues, the net amount to be recovered from rates for the default supply was $216,526,810 for the 2004/2005 tracking period.

60. When NWE filed its last general rate case (Docket No. D2000.8.113), the cost of service for the MPSC and MCC tax were based on test year 1999 Transmission and Distribution revenue only. The Electric Supply Buy-back Contract rates did include recovery of the MPSC and MCC fees until their expiration on June 30, 2002. Electric Default Supply rates since that time have not included recovery of the PSC and MCC fees. NWE has been paying and will continue to pay these fees based on total revenue, including supply. NWE proposed recovery of the PSC and MCC fees based on rates which were current at the time of the filing applied to the estimated supply revenues to be billed.

61. Ms. Hansen stated that NWE continued to promote the use of monthly trackers for the reasons stated in her testimony in Docket No. D2003.6.77.

**William Thomas**

62. William Thomas' prefiled direct testimony focused on three topics: 1) demand-side management programs NWE plans to implement within the default supply portfolio, 2) tracking and recovering DSM program costs and foregone transmission and distribution revenues associated with successful DSM, and 3) restructuring certain USB DSM programs to transfer a portion of that DSM activity into the default supply portfolio.

63. NWE's 2004 default supply resource plan called for acquiring 2.6 aMW of DSM in 2004-2005, ramping to 5 aMW by 2006-2007 and remaining at that level thereafter. According to Mr. Thomas, once DSM acquisition levels off at 5 aMW per year, the annual cost will also level off at about $7.4 million per year. These DSM targets include energy saving from both USB and default supply portfolio DSM programs.

64. The DSM assessment in NWE's 2004 default supply plan identified energy efficient lighting as a major source of cost-effective energy savings. Therefore, NWE's initial

incremental DSM acquisition strategy focuses on lighting incentive programs for residential and small/medium business customers. According to Mr. Thomas, subsequent programs will target other energy end-uses, building envelopes and new construction. NWE will promote participation in DSM programs by offering customers cash incentives or rebates toward the purchase and installation of approved measures. Mr. Thomas, in Exhibit_(WMT-1) of his testimony, summarized planned residential and commercial DSM programs and the various methods for promoting customer participation.

65. On an on-going basis, NWE will monitor customer participation and verify the installation of measures through a combination of on-site inspections, other proof of installation, such as paid invoices, and customer self-certifications with random site inspections. Mr. Thomas stated that NWE will use internal staff resources whenever possible to provide DSM program services. NWE personnel will design and administer programs and conduct promotion and outreach activities throughout the service area. NWE administrative staff will prepare and issue competitive solicitations to retain outside contractors for certain work, like installing measures, verifying installed measures on-site, evaluating program performance and verifying savings.

66. Mr. Thomas proposed using NWE's default supply cost tracking mechanism to also track and recover the costs of DSM programs and associated lost transmission and distribution revenues. According to Mr. Thomas, this approach would ensure that NWE's default supply, transmission and distribution businesses are made financially whole for DSM expenditures and would mitigate disincentives to acquiring DSM resources that are important for the overall default supply portfolio.

67. Regarding lost transmission and distribution revenues, Mr. Thomas asserted that DSM-induced load reductions cause NWE to under recover the energy delivery component of NWE's annual revenue requirement authorized by the Commission in a prior rate case. The Commission sets the energy delivery component of the revenue requirement, and rates to collect it, using test period costs and weather-normalized sales volumes. Between rate cases, according to Mr. Thomas, DSM programs reduce loads and cause the usage-based energy delivery rates to become increasingly insufficient to recover energy delivery-related costs allowed by the Commission. Mr. Thomas's Exhibit_(WMT-3) numerically illustrates how successful DSM programs reduce transmission and distribution revenues between rate cases. Mr. Thomas stated that without regular rate adjustments to recover DSM program costs and lost transmission and

distribution revenues, NWE will lose money between rate cases. NWE could mitigate this impact by reducing the amount of DSM it acquires, or by slowing the rate at which it acquires DSM. But that would increase the overall cost of the default supply portfolio in the long term.

68. Mr. Thomas reasoned that a lost revenue adjustment within the default supply tracker would remove the financial disincentive to aggressively pursue DSM resources by protecting NWE's financial health. He proposed a DSM tracking adjustment to default supply rates to recover projected DSM program expenses and lost transmission and distribution revenues for a 12-month period. After the initial 12-month period, and in subsequent annual filings, the tracker would true up the prior year's revenue collection using actual energy sales, DSM program expenses and reported kWh savings and lost transmission and distribution revenues. Any under/over collection is incorporated into the default supply rate adjustment for the subsequent 12-month period along with projected DSM program costs and lost transmission and distribution revenues. Mr. Thomas demonstrated the proposed DSM program cost and lost revenue tracking calculations in his Exhibit_(WMT-4).

69. For the 2004-2005 tracking year, NWE estimated it would incur $1,457,888 in DSM program expenses and $273,196 in lost transmission and distribution revenues. NWE proposed a total adjustment to default supply rates of $1,731,084.

70. NWE plans to hire an outside, independent evaluator in the third quarter of 2006 to analyze DSM program records and data, survey program participants, inspect the installation of measures, assess changes in energy consumption and determine the amount of energy savings actually produced through NWE's DSM programs. The independent evaluator will quantify the persistence of verified energy savings over time, study NWE's process for delivering DSM programs to customers and recommend ways to improve future results. Mr. Thomas stated that NWE will use the results of this independent evaluation to refine energy savings estimates for each DSM program measure, re-assess existing cost-effectiveness tests, and improve the accuracy of DSM budgets and adjustment factors used in DSM tracking calculations.

71. Along with ramping-up DSM programs in the default supply portfolio, NWE will modify two existing USB programs: E+ Business Partners and E+ Commercial Lighting. Mr. Thomas testified that these two USB programs are designed to acquire energy efficiency resources from choice and non-choice customers. Most of the participants in these USB programs are default supply customers and NWE plans to introduce a new commercial lighting

program, within the default supply portfolio, in January 2005. At the same time, NWE will change the USB E+ Business Partners program so that, going forward, it is only available to choice customers.

72. NWE plans to maintain the USB E+ Business Partners program until July 2005. At that time, NWE will introduce a new DSM program within the default supply portfolio to address commercial site-specific energy efficiency opportunities/proposals and the USB E+ Business Partners program will transform into a program for choice customers.

73. Existing universal system benefits charges pay for USB DSM programs. However, according to Mr. Thomas, the DSM budget developed in the 2004 default supply plan is based on a build-up of cost-effective measures. So, the total $3.8 million DSM budget that acquires 2.6 aMW in the first tracking year includes energy savings from USB programs and a portion of this total budget consists of existing universal system benefits funds. Mr. Thomas stated that since USB programs are not always cost effective from a default supply portfolio perspective, the portfolio should not recognize all USB expenditures for purposes of program cost recovery. Rather, Mr. Thomas stated, the portfolio should recognize the value of USB-produced DSM at the average cost for all DSM. NWE estimated the average cost of all DSM at $1,487,281 per aMW (approximately $3.8 million ÷ 2.6 aMW). Mr. Thomas proposed valuing USB energy savings at this average cost and recovering the remainder of the total DSM budget through the default supply tracker.

74. Finally, Mr. Thomas stated that all DSM programs, including USB programs, reduce energy sales and contribute to lost transmission and distribution revenues. Therefore, he proposed that the DSM tracking calculation include lost revenues from both default supply DSM and USB DSM.

**William Thomas - Supplemental Testimony on Additional Issues**

75. In Order No. 6574b, the Commission identified several additional issues in this proceeding: the reasonableness of the allocation of NWE's universal system benefits funds among qualifying categories, alternatives to monthly default supply rate adjustments, and the merits of capitalizing investments in DSM. In Order No. 6574c the Commission adopted a stipulation between NWE, Montana Consumer Counsel, Montana Office of Northwest Power and Conservation Council, District XI Human Resource Council, Renewable Northwest Project,

Natural Resources Defense Council and AARP Montana requesting that the Commission authorize a one-time transfer of $621,274 from year 2005 USB conservation and market transformation programs to electric and gas low-income discounts, defer consideration of issues related to USB, and initiate a new docket to address all USB-related issues after the 2005 session of the Montana legislature. Pursuant to these Orders, NWE filed supplemental testimony by Mr. Thomas.

76. With respect to monthly default supply rate adjustments, Mr. Thomas testified that it is important to provide customers with timely information on actual costs and market price trends so they make informed energy consumption decisions. Since actions by a subset of default supply customers can affect the cost for all customers, Mr. Thomas asserted that customers should want all other customers to consume energy in ways that, at least, do not adversely affect their own energy costs. Although NWE will evaluate time-variable pricing, Mr. Thomas said it is unlikely all customers would voluntarily participate in such programs. Therefore, monthly price adjustments will continue to be an important tool for conveying price information.

77. From a financial standpoint, Mr. Thomas stated monthly rate adjustments better match revenues and expenses and reduce carrying charges associated with deferred cost recovery/refunds. Mr. Thomas does not appear to believe that monthly rate adjustments create unreasonable instability. He asserted that NWE uses a forward-looking, 12-month rolling average projection of supply costs which smoothes rate changes, that only 25% of the portfolio is exposed to market volatility and that the influence of market volatility will decline as NWE adds additional resources to the portfolio. Since monthly rate adjustments are approved on an interim basis subject to true-up and a prudence review in an annual proceeding, Mr. Thomas stated that monthly rate adjustments neither encourage nor discourage cost control.

78. Mr. Thomas testified that other Montana utilities use monthly price adjustment mechanisms for the same reasons NWE favors them and that regulatory consistency counsels against taking this tool from one utility alone; if any regulatory change is made, it should follow a broader forum that includes all utility companies, consumer representatives and other parties.

79. On the issue of capitalizing DSM, Mr. Thomas stated that DSM program costs should be treated the same way all other default supply portfolio costs are treated. Currently all other default supply costs are treated as monthly wholesale electricity expenses that are passed

directly through to customers. Mr. Thomas stated that under NWE's DSM procurement plan, which calls for ramping-up DSM investments for several years to a level that will then be quite constant, ultimately the level of total amortized costs is equal to expensing everything in a single year. According to Mr. Thomas, a capitalization approach appears to provide customers value in the short-term, but is more costly in the long-term because of the return component on the unamortized portion of the investments and the financing costs. Mr. Thomas asserted that capitalizing DSM investments also creates regulatory assets and the associated risk of future stranded costs.

**Mark Thompson**

80. Mark Thompson pre-filed direct testimony that described NWE's power purchase agreements with the Thompson River Co-generation (TRC) project and the Tiber Montana (Tiber) hydro project.

81. The TRC project is a 16 MW thermal generation facility in Thompson Falls, Montana. The facility is primarily fueled by coal, but up to 30% of the fuel could be wood waste from an adjacent lumber mill. Mr. Thompson testified that the facility would incorporate state of the art emission controls and steam produced by the facility would be used by the lumber mill, allowing it to retire several old and inefficient boilers.

82. The power purchase agreement with TRC provides unit-contingent, base load energy at a fixed $40 per megawatt hour for ten years. Mr. Thompson estimated that the facility would produce about 100,000 megawatt hours of energy per year, implying an annual cost to the default supply portfolio of $4,000,000. The terms of the power purchase agreement require TRC to schedule planned plant outages cooperatively with NWE. According to Mr. Thompson, NWE and TRC committed to discuss possible term extensions; at this time TRC has not contracted long-term for coal supplies and is reluctant to lock in prices until its fuel costs are more certain.

83. NWE did not procure TRC directly from a RFP. Montana Power Company initially brought the TRC resource to the Commission requesting pre-approval of a proposed contract in Docket No. D2001.10.144. In that Docket, the Commission declined to grant the pre-approval, finding that under statutes in effect at the time, contracts premised on Commission approval were

not truly resource procurements.[1] After NWE purchased Montana Power Company, it continued to negotiate with TRC over the terms of a power purchase agreement. According to Mr. Thompson, before NWE entered the TRC contract it compared TRC's price with prices offered by four larger coal facilities in recent NWE RFPs. Mr. Thompson stated that the TRC price was competitive with these other offers. Additionally, Mr. Thompson said the TRC price was within 2.5% of the Northwest Power and Conservation Council's estimates for new coal-fired generation.

84. Mr. Thompson testified that NWE was prudent to execute a power purchase agreement with TRC. He reiterated that the price was competitive with bids received for larger projects in a RFP. He also stated that NWE reviewed the engineering design for TRC to ensure the project was sound. Finally, NWE's portfolio modeling demonstrated that TRC would provide portfolio benefits. Mr. Thompson also described economic benefits associated with construction and operation of the project and new property tax revenues. He said environmental benefits would derive from displacing the old, inefficient boilers at the lumber mill and from efficiently burning wood waste.

85. Tiber is a 7.5 MW hydroelectric generator on the Marias River in Chester, Montana. Mr. Thompson estimated the average annual output from the project would be 4 MW. He said power from Tiber qualifies as renewable energy because is based on run-of-river and there are no environmental or fishery issues related to the power generation. The NWE-Tiber power purchase agreement provides for seasonal energy supply from November through April each year of the 20-year term. Mr. Thompson said the six month supply structure complements higher base load default supply requirements in the winter season and also allowed NWE to negotiate a better price.

86. Mr. Thompson testified that the Tiber pricing structure is segmented into two, ten-year periods. The price in each ten-year period averages $38.93 per megawatt hour and the estimated price in the first and eleventh years is $35.57 per megawatt hour. Mr. Thompson stated that the average annual cost to the portfolio of the Tiber energy is about $930,000.

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[1] See Order 6382d, June 21, 2002, pp. 9-14. At the time, § 69-8-210, MCA, required the utility to "procure a portfolio of electricity supply" to "provide for the full electricity supply requirements of all default supply customers." The utility was authorized to submit material related to proposed bids or contracts before it entered the contracts and the Commission was authorized to comment on such material.

87. Like TRC, Tiber was also initially brought to the Commission by Montana Power Company as a proposed resource in Docket No. D2001.10.144. NWE also compared the Tiber price to the four base load coal offers received in a RFP. Mr. Thompson stated that, like TRC, Tiber was competitive with the base load coal bids and was more economical than the Northwest Power and Conservation Council's estimated cost of new coal facilities. Portfolio modeling demonstrated that Tiber would provide benefits to the default supply portfolio, according to Mr. Thompson. For these reasons, Mr. Thompson testified that NWE was prudent to execute the Tiber contract.

**Intervenor Testimony**

**AARP Montana**

88. Barbara Alexander pre-filed direct testimony for AARP Montana. She addressed the following issues: 1) proper allocation of USB funds, 2) NWE's proposal to recover lost transmission and distribution revenues due to DSM activity, 3) whether NWE should capitalize its DSM investments, and 4) whether NWE should continue using a monthly default supply rate adjustment procedure.

89. Ms. Alexander supported acquisition of cost effective DSM in the default supply portfolio. She also supported transferring cost effective DSM programs from USB activity to default supply activity. Although the Commission resolved USB allocation issues for 2004-2005, she recommended that the Commission initiate a separate docket in 2005 to address USB-related issues for all Montana electric and gas utilities. That proceeding should establish policies that govern the allocation of DSM programs between USB and default supply funding streams and the proper allocation of USB funds among qualifying public purposes.

90. Although Ms. Alexander stated that NWE's concerns over calculating and recovering lost transmission and distribution revenues associated with DSM are legitimate, she recommended against approving the approach NWE proposed in this case. Instead, she stated that the matter should be addressed in NWE's next rate case since it is directly related to distribution service rates, which, in turn, include a return component on regulated assets. She reasoned that, pursuant to the Bankruptcy Settlement, NWE will be filing a rate case no later than 2006, based on a 2005 test year and the impact of the 2004-2005 DSM programs will be

reflected in the 2005 test year. She asserted that the lag between the implementation of DSM programs in 2004-2005 and up-coming rate case is relatively insignificant.

91. If, instead, the Commission decides to address the lost T&D revenues issue in this docket, Ms. Alexander recommended two alternatives to NWE's approach. The first would authorize NWE to implement a lost T&D revenues tracker, but would not allow actual recovery of lost revenues until they are confirmed after-the-fact by a third-party using actual performance data for approved DSM programs. She said this approach has been adopted by the Massachusetts Department of Telecommunications and Energy. The second alternative would involve developing a share the savings approach where NWE would be allowed to recover the cost of the DSM programs plus some share of the net economic benefits produced by the DSM programs. This alternative would, apparently, require the Commission to initiate a separate proceeding to develop the details of this incentive approach.

92. On the issue of whether NWE should expense or capitalize DSM investments, Ms. Alexander testified that AARP Montana addressed this issue in its written comments on NWE's 2004 Default Supply Resource Procurement Plan and she did not have further recommendations for changes in NWE's proposed method. In her response to data request PSC-023a, Ms. Alexander stated that AARP Montana has chosen not to take a position on this matter in this proceeding, in part because comparing the approaches requires an analysis of the useful lives of various DSM measures, depreciation methods and reasonable rates of return and she is not an accountant or financial specialist. Her response to data request PSC-023c suggests that § 69-3-712, MCA, may require a capitalization approach as MCC recommends.

93. Ms. Alexander recommended that the Commission adopt incentives within the default supply tracking mechanism that would endow NWE with a stake in the management of supply costs, especially the stability of those costs. According to Ms. Alexander, one way to do this would be to switch from monthly rate changes to annual rate changes, at least for residential and small commercial customers. Ms. Alexander disputed NWE witness, Mr. Thomas' view, that residential customers' consumption behavior is influenced by monthly price changes. She said recent evidence suggests residential customer usage is inelastic and that Puget Sound Energy's time-of-use experiment was stopped because customers were not successful in shifting their usage patterns. She cited New Jersey, Maryland, Maine and Pennsylvania as examples of states that have adopted more stable pricing methods for residential customers while allowing

more frequent price changes for larger customers. She asserted that implementing annual price changes for residential customers would favor longer term, fixed price contracts and less reliance on short-term wholesale market purchases.

**Commercial Energy of Montana**

94. Ron Perry prefiled direct testimony for Commercial Energy of Montana (CEM). Mr. Perry's testimony focused on NWE's analysis of default supply cost impacts due to the return of choice customers previously served primarily by CEM. Mr. Perry asserted that imposing a surcharge on returning choice customers (RCC) in this docket would not be consistent with past Commission practice. Mr. Perry stated that while in the case of the League of Cities and Towns, where 20 MW of load returned without any surcharges, in this case the Commission/staff asked NWE to specifically estimate the effect of RCCs previously served by CEM even though there was no single day in which more than 5,000 KW of load filed to return to default supply. Mr. Perry further maintained that the NWE tariff governing RCCs took effect June 30, 2003, but has only been applied to RCCs in this case, not in other cases like the League of Cities and Towns.

95. According to Mr. Perry, the only explanation for the apparent disparate treatment of the former CEM customers occurred at a June 30, 2004 PSC work session where Commission staff referred to possible intent by those customers to abuse the process, and, based on that, concluded that the customers should be considered a group for purposes of applying NWE's tariff. Mr. Perry asserted that Commission staff did not offer actual evidence of an intent to abuse the process. Mr. Perry also said the RCCs formerly served by CEM were not provided any notice that Commission staff viewed them differently from other RCCs.

96. The word "group" is not defined in the NWE tariff that governs RCCs. Mr. Perry observed that Commissioners and staff struggled at the June 30, 2004 work session over how to apply the definition of "group" in the context of the tariff. He said the work session discussion showed that the term "group" should have been more adequately defined, if used at all, and that, given the clear ambiguity, it would be unfair for the Commission to impose a surcharge of the magnitude contemplated in this case. It appears to Mr. Perry that the definition of "group" applied in this case so far hinges on a temporal relationship between the RCCs. He said this approach is flawed because the tariff does not specify relevant time periods so it would be impossible for a customer contemplating returning to default supply to make a rational business

decision – either taking actions to avoid being part of a group, or deciding not to return if being part of a group is unavoidable.

97. Mr. Perry testified that attempting to enforce vague tariff language would be bad public policy. The Commission is responsible for setting just and reasonable rates and, according to Mr. Perry, key aspects of just and reasonable rates are stability and predictability, which allows customers to make economically rational decisions. Additionally, to maintain reasonable opportunities for customer choice, as required in § 69-8-201 (5), MCA, predictable, knowable and rational market rules must exist. Mr. Perry asserted that applying a surcharge without notice and in an inconsistent manner contradicts the legislature's direction to afford reasonable opportunities for choice. Mr. Perry recommended providing potential RCCs an advanced estimate of their potential liability before they make a final decision.

98. Mr. Perry believes choice customers maintain specific rights to specific megawatt hours of energy from specific default supply contracts. See CEM response to data request PSC-015. He testified that NWE's current contracts with PPL Montana were approved by the Commission in Order 6382d to serve default supply customers and manage customer migration to and from choice. According to Mr. Perry, had the RCCs remained default supply customers for the past two years, 75% of their annual load would have been served by the PPL and QF contracts at an average price of $32.04 per megawatt hour. But since these customers were supplied by CEM, NWE was able to avoid purchasing 150,000 megawatt hours in the wholesale market at $42.00 per megawatt hour. Mr. Perry concluded that "by not taking their proportionate share of the default supply contracts with them, the RCCs benefited the default supply customers by over $3.8 million. And he maintained that statutory changes adopted by the 2003 Legislature did not eliminate CEM's customers' rights to the remaining years of their proportionate share of the PPL Montana and QF contracts. Mr. Perry further reasoned that it would not be fair to assess choice customers a QF-related competitive transition charge and not provide RCCs a proportionate share of the in-market QF power when it would benefit the customers.

99. Mr. Perry testified that the rate protection required in § 69-8-201(5), MCA, is directed at small customers and that the Commission should not allocate any incremental default supply cost due to RCCs only to the RCCs, but should spread the cost among all mid-size and large default supply customers. To do otherwise, according to Mr. Perry, would be to provide rate protection to customer classes not authorized in the statute. Mr. Perry also suggested that it

would be fair to establish a stable, prospective fee of about 1% of the default supply rate for all commercial and large customers with the ability to come and go from default service.

100. Finally, Mr. Perry asserted that despite NWE's $1.08 million original estimate of the incremental default supply cost due to RCCs, he suspects that in the final analysis, actual incremental costs will be negligible. He noted that for the first three months of the tracking period actual hourly costs suggested no incremental costs. He recommended that the Commission require NWE to update its analysis to reflect actual wholesale prices.

**District XI Human Resource Council, Natural Resources Defense Council, Renewable Northwest Project**

101. Thomas Power prefiled direct testimony for joint intervenors District XI Human Resource Council, Natural Resources Defense Council and Renewable Northwest Project (hereafter District XI). Dr. Power's testimony focused on NWE's plan to expand its DSM programs, expensing versus capitalizing DSM investments, and tracking and recovering lost transmission and distribution revenues due to DSM.

102. In a short background section, Dr. Power explained that in Docket No. D2001.10.144 he testified that Montana Power Company's proposed default supply portfolio did not adequately acquire cost-effective DSM resources and, as a result, did not minimize the cost to serve default supply customers or protect them from cost volatility as well as a portfolio with more cost effective DSM would. At that time he recommended that MPC spend an additional $7 million on DSM each year over a ten year period and urged the Commission to address regulatory barriers that discourage the default supplier from investing in DSM, including expensing rather than capitalizing DSM and removing the lost revenue disincentive. In January 2003, NWE commissioned a thorough assessment of the potential DSM resource in its Montana service area. NWE's Technical Advisory Committee advised the Company on the design of this assessment. The results indicated that at high incentive levels about 100 aMW were achievable from default supply customers. In its 2004 Default Supply Resource Procurement Plan NWE proposed acquiring this resource over a 20-year period, about 5 aMW per year after an initial ramp-up.

103. Although NWE proposed to proceed to acquire DSM resources more slowly than he recommended in Docket D2001.10.144, Dr. Power stated that he supports the Company's DSM procurement strategy. He said NWE's target to acquire 2.6 aMW the first year, increasing to 3.7

aMW the second year and leveling off at 5 aMW is reasonable as NWE develops new capacity to pursue DSM and gains experience with expanded programs. However, since customer loads can be served at less than half the cost of conventional supply with DSM, he emphasized that NWE's rate of DSM acquisition should be reevaluated after the ramp-up period and possibly accelerated. NWE's DSM procurement targets include both USB and default supply programs, and the USB programs include a portion of non-cost-effective DSM. Dr. Power pointed out that once savings from these programs are subtracted from NWE's targets, the Company is actually proposing to acquire less DSM resource in the default supply portfolio than its DSM assessment indicated was achievable.

104. Dr. Power supported NWE's proposal to expense DSM investments in the year they are made. He said although energy supply investments would normally be amortized over their productive lives, DSM investments do not produce physical assets controlled by the Company. Instead, they are made in customer-owned facilities and become the property of those customers. As a result, capitalizing DSM creates a "regulatory asset" where what supports the financing of the investment is the regulator's "promise" that the costs are recoverable. According to Dr. Power, investors and accountants do not treat regulatory assets the same as physical assets, and due to uncertainty about future customer choice, regulatory assets look even less attractive. Given that all current default supply costs are effectively expensed because of NWE's reliance on purchases rather than its own generation (there is no default supply rate base), Dr. Power asserted that it would be reasonable to treat DSM investments the same way. The size of the planned DSM investments suggests that the impact on rates from expensing rather than amortizing them would be quite small.

105. As NWE witness Mr. Thomas described, the total $3.8 million first-year DSM budget to acquire 2.6 aMW includes program costs and energy savings from both USB programs default supply programs. Therefore, a portion of this total budget would be funded by existing universal system benefits charges. Dr. Power observed that Mr. Thomas' explanation of the procedure for determining default supply cost responsibility is unnecessarily complicated. The default supply portfolio's share of the total budget is simply the sum of the costs of all DSM programs not funded by the USBC. Dr. Power did not see a need for NWE to first value USB DSM programs at the average cost of all programs, add it to the default supply DSM costs and then subtract out the USB DSM costs. All NWE needs to do is track the source of the funding

for various programs and exclude from the default supply tracker costs that are recovered through the USBC.

106. NWE proposed to shift much of the USB E+ Business Partners and E+ Commercial Lighting program activities from USB to the default supply portfolio. NWE also proposed to retain the PSC-approved overall allocation structure, re-allocating funds "freed-up" from this shift to other energy efficiency and market transformation programs. Dr. Power testified that NWE's proposal is reasonable. However, he said meetings of NWE's various USB advisory committees are long overdue. He also supported a systematic Commission review of the allocation it ordered several years ago, but in a separate docket.

107. Dr. Power supported NWE's proposed lost revenue adjustment in the default supply tracker with a modification to incorporate true-ups that reflect actual savings determined by after-the-fact program evaluations. He also recommended that, after NWE and the Commission have some experience with the proposed lost revenue adjustment, the Commission evaluate it along side other possible approaches.

108. Dr. Power justified the reasonableness of a lost revenue adjustment by noting that it is unusual for a private business to invest money that helps customers buy less of its products. NWE faces a disincentive to encouraging greater energy efficiency because part of its fixed costs are recovered through usage-related rates. If, during the years after rates are set to recover NWE's fixed costs, it implements DSM programs, usage will decline, other things being equal, and it will not generate the revenues to recover its fixed costs. In effect, NWE would be penalized for implementing DSM programs. According to Dr. Power, that is not an appropriate regulatory scheme because it punishes good behavior, behavior in which the Commission has, in fact, ordered NWE to engage.

109. Dr. Power acknowledged that between rate cases all other things are not equal; loads tend to grow and NWE has opportunities to cut costs through better management and technological innovation. Although these changes produce additional revenue and profit between rate cases, which off-set revenue lost due to DSM activity, Dr. Power asserted that these changes are part of the incentive structure that encourages business-like behavior. The "regulatory lag" between rate cases promotes entrepreneurial activity designed to "beat" cost and revenue benchmarks used in rate cases. Dr. Power asserted that the proper reference point for analyzing the DSM incentive is the revenue level NWE could achieve if DSM was not acquired.

Successful DSM will reduce NWE's revenues and profits relative to what it otherwise would achieve, and therein lies the disincentive. Furthermore, Dr. Power pointed out that the Commission has directed NWE to treat supply- and demand-side resources as equally capable of serving customer loads. If NWE is asked to treat these two types of resources the same, the incentive structure NWE faces should be symmetrical too.

110. Dr. Power stated that although NWE's lost revenue adjustment proposal is simple and transparent, it is flawed because it sets rates based on projected results with no true up once actual results are known. That is not good regulation. Dr. Power recommended that the Commission direct NWE to fund independent, regular and critical evaluations of DSM programs to assess the actual impacts of the programs. The results of these evaluations should be used to true up lost revenue adjustments. For example, if a program were not working as planned, NWE's rates would be adjusted downward to give back revenues that were not actually lost in previous tracker periods.

111. If the DSM disincentive is rooted in the fact that NWE recovers fixed costs through usage charges, one might ask whether it would make sense to redesign the rate structure so that fixed costs are recovered through fixed monthly charges. Then fluctuations in usage would not affect NWE's revenue. Over the years Montana Power Company, and many other utilities around the country, according to Dr. Power, have proposed such rate structures. However, Dr. Power asserted that he strongly opposes such rate structures and would not recommend them as a solution to the lost revenue problem. According to Dr. Power high monthly charges reduce the incentive and reward for reducing consumption. With smaller savings potential, customers would be less likely to adopt DSM measures that improve efficiency. According to Dr. Power, when the incremental cost of new electricity supply is expected to increase in the future, reducing usage-based rates sends the wrong signal to customers. And when the environmental costs of electricity generation are considered, the distorting effect of reduced usage charges becomes clearer. Beyond that, Dr. Power maintained that high monthly charges disproportionately burden lower income households because such households generally use less energy.

112. Other regulatory mechanisms have been developed to address the incentives faced by utilities with regard to acquiring DSM, for example mechanisms that allow the utility to share the savings produced by DSM. Dr. Power stated that such mechanisms provide utilities positive

incentives and, therefore, might complement a lost revenue recovery mechanism. However, Dr. Power said he questioned the adequacy of such mechanisms as substitutes for a lost revenue recovery mechanism, in part due to the potential difficulty of matching the financial benefits of the positive incentive with the financial disincentive of lost revenues.

113. There are other regulatory models around the country for allowing utilities to recover lost revenues from DSM. Dr. Power recommended that the Commission's final order in this docket direct NWE to file an evaluation of its lost revenue approach compared to others in use around the country. The evaluation should be filed after two years of experience with NWE's approach. This would provide the Commission and interested parties a basis for assessing whether NWE's approach should be continued on a longer-term basis.

114. Although this Docket is focused on the narrow question of incentives/disincentives associated with NWE's acquisition of DSM resources, Dr. Power takes the opportunity to discuss the issue of incentives and disincentives in a broader sense. He asserted that, ideally, regulation should consist of a system of appropriate incentives that both reward good behavior and outcomes and penalize bad behavior and outcomes. He said default supply activities are currently performed by NWE as a non-profit, public service function. The Company earns no more money if it does a particularly good job and it does not necessarily earn less money by doing a modestly poor job. Dr. Power observed that this is an anomaly in the business world; NWE makes hundreds of millions of dollars in electricity purchases each year to serve customers, but has nothing at stake. As long as it acts prudently it is not at risk and has nothing to gain. He attested to the fact that today NWE takes its default supply obligations seriously and has vigorously and imaginatively sought ways to keep the cost of supply as low as possible but that the environment in which NWE conducts its default supply activities normally would cause a rational company to try to shift as much risk as possible to customers. Although NWE and others may prefer such a no-risk, no-profit environment, Dr. Power asserted that complex organizations rarely work well when there is no system of incentives to motivate good behavior and discourage bad behavior. In the long-run, this environment likely will lead to higher costs and higher risks for customers. He emphasized that he is not criticizing the Commission, NWE or other parties. Rather, in light of the discussion of a mechanism to remove a disincentive to optimally acquiring DSM resources, he suggested that the overall incentive system NWE faces is still quite incomplete.

**Montana Consumer Counsel**

115. John Wilson prefiled direct testimony for MCC. Dr. Wilson testified that the default supply costs NWE seeks to recover for the two 12-month periods ending June 30, 2003 and June 30, 2004 are reasonable, for the most part, and should be approved. Dr. Wilson said elements of NWE's cost recovery approach pertaining to QF replacement costs and default supply portfolio market purchases are questionable and should be modified in future electric tracker filings. MCC and NWE discussed the QF replacement cost issues and reached agreement on a method for quantifying these costs in the future. MCC and NWE submitted a Stipulation Agreement on June 3, 2005 that specified the method.

116. The QF replacement cost issue has its roots in a prior stipulation approved by the Commission in Docket Nos. D97.7.90 and D2001.1.5 which resolved transition cost issues and authorized the sale of Montana Power Company to NorthWestern Energy. NWE agreed to deliver a specific quantity of energy (809,002 Mwh) from QF contracts at a specific price ($32.75/Mwh) in order to serve default supply customers. If actual QF production is less than the specified quantity, NWE must replace the shortfall at the stipulated price. Dr. Wilson explained that, as evidenced by its filings in this case, NWE believed it had only a total annual QF energy obligation and could make up for QF shortages at times during the year that might differ from the time of the actual the QF outage. In practice, NWE has timed QF shortfall replacement purchases so they are most economic from a Company perspective. Dr. Wilson stated that since NWE views QF supply as base load supply, NWE generally made up for QF shortfalls by assigning base load supply purchases rather than attributing spot purchases, such as those used to cover supply deficiencies during peak periods.

117. Dr. Wilson stated that in both the 2003-2004 and 2004-2005 tracking periods the QF projects produced less than the stipulated quantity, requiring NWE to replace about 233,000 Mwh in 2002-2003 and 86,000 Mwh in 2003-2004. According to Dr. Wilson, in both tracking periods NWE's cost to replace the QF deficiencies was well below $32.75, about $22.60/Mwh in 2002-2003 and about $22.50/Mwh in 2003-2004. Since NWE recovers $32.75/Mwh in default rates for all QF power, NWE experienced a net gain of about $2.365 million in 2002-2003 and $881,500 in 2003-2004. Dr. Wilson stated that QF replacement costs could be higher or lower than the stipulated price and there is no requirement for NWE to credit ratepayers with gains associated with low cost replacement energy.

118. However, Dr. Wilson observed that power purchase costs NWE assigned to QF replacements were substantially lower than power purchase costs assigned to the default supply portfolio. NWE's default supply market purchases averaged $33.00/Mwh in 2002-2003 and $41.00/Mwh in 2003-2004. According to Dr. Wilson, the difference between the QF replacement costs and default supply market purchases could not always be explained by the timing of QF outages. For example, QF production was substantially deficient during the first half of the 2003-2004 tracking period, but not in the second half of the period. But while the default supply market purchases during the first half of the tracking period exceeded $40.00/Mwh, NWE assigned part of a firm power purchase from Avista, priced at 22.50/Mwh, that occurred in the second half of the tracking period (April – June 2004) to make up for the QF deficiencies from the first half of the tracking period. Dr. Wilson asserted that ultimately about 79% of the Avista purchase was assigned to make up QF deficiencies and 21% was assigned to the default supply portfolio.

119. Dr. Wilson stated that the key language in the stipulation (D97.7.90./D2001.1.5) requires that NWE:

> Shall be responsible for the delivery of replacement power, if needed, to meet the QF energy volumes shown in Appendix D at the scheduled prices shown in Appendix D. Delivery of this replacement power shall conform to the historical energy deliveries of the QF resource, or resources, for which the replacement power is required.

120. According to Dr. Wilson, this language suggests that QF replacement power should match expected or budgeted QF deliveries. If unexpected QF outages at peak times require NWE to obtain replacement energy, the cost of the replacement energy at that time, or a reasonable proxy therefore, should be assigned to QF replacement. Dr. Wilson stated that the wording of the stipulation was not intended to allow NWE to make up for QF outages that occur when replacement costs are $40/Mwh with springtime runoff purchases in later months at half that cost.

121. MCC and NWE specified in their June 3, 2005 stipulation a procedure for quantifying the cost of QF replacement energy that they agree should be used in future tracker filings. NWE would focus on minimizing the cost of all required market purchases and the cost assigned to QF replacement energy each year (if any) would be the lower of the average cost of those market purchases or the average mid-Columbia price for the year. Dr. Wilson stated that the "lower of" aspect of the stipulation is reasonable because in some years NWE's actual short-

term purchases will be dominated by resource deficiencies during peak periods when market prices are higher than average, while there is no reason to expect that QF deficiencies will be concentrated at peak hours. In situations where a QF outage is known in advance and would exceed 90 days, NWE would have the option of procuring a specific replacement for the outage period.

122. Dr. Wilson finds reasonable NWE's proposal to include DSM expenditures in the annual default supply cost tracker because they are subject to documented true-up in subsequent filings. However, he asserted that lost transmission and distribution revenues represent a less verifiable cost that would probably be offset by other sales volume changes between rate cases. Dr. Wilson identified two problems with making adjustments to default supply revenue requirements based on estimated lost T&D revenues: 1) identifying and isolating sales reductions attributable to DSM programs is speculative, and 2) DSM-related sales changes are only one type of sales change that normally occurs between rate cases. Dr. Wilson suggested that increases in the number of customers along with technology and income-induced consumption changes probably more than offset sales reductions due to DSM between rate cases. Making a piecemeal adjustment that reflects only estimated DSM sales reductions and not offsetting sales changes would cause total revenues to further diverge from the cost of service. Therefore, Dr. Wilson recommended against piecemeal cost of service adjustments such as the lost T&D revenue adjustment NWE proposed.

123. Dr. Wilson noted that because DSM program costs in a given year are expected to produce a stream of benefits for many years, NWE's proposal to expense DSM program costs annually rather than capitalize them creates an equity issue. Ratepayers in the first year of a DSM program would pay the full annual cost of the program but would only receive a portion of the benefits, while ratepayers in year ten would pay annual DSM program costs for year 10, but would receive benefits that have built up over years 1 through 9. According to Dr. Wilson, a better way to match program costs and program benefits over time is to capitalize DSM program costs. Dr. Wilson noted that rate impact differences between capitalizing and expensing DSM will be greatest in early years when, under capitalization, ratepayers would be charged only a portion of NWE's annual expenditure. Eventually, the annual cost to ratepayers under the capitalization approach and the expense approach would be about equal. According to Dr. Wilson, under the capitalization approach, NWE's ratepayers would pay $14.8 million less

during the first 6 DSM program years than they would if NWE were allowed to expense DSM program costs each year (MCC-1 p. 20). This is appropriate, Dr. Wilson said, because the main difference between expensing and capitalizing is that with expensing ratepayers in the early years subsidize ratepayers in later years.

124. Beginning on p. 20 of his testimony, Dr. Wilson described a contract dispute between NWE and PPL Montana over whether an outage of the Corette plant in June 2004 was related to a scheduled plant outage, which would require PPL Montana to provide replacement power at the contracted rate, or an unscheduled outage, which would require NWE to obtain replacement power at market rates. PPL Montana had taken Corette out of service on May 26 for a planned 15 day maintenance period. The plant returned to service on June 10, as scheduled, but was forced out of service again on June 15 by a turbine control failure. The plant remained out of service until July 2. PPL stopped delivering energy to NWE in an amount equal to Corette's output on June 17, forcing NWE to acquire spot energy at much higher prices. According to Dr. Wilson, NWE believes the Corette outage that occurred a week after the end of the planned outage was a continuation of problems which prompted the scheduled outage and, therefore, the terms of the contract did not excuse PPL Montana from delivering replacement energy. NWE told PPL Montana that it would withhold $100,960 from its payments to cover its incremental supply costs. PPL Montana asserted that the second Corette outage was a new, unscheduled outage so the contract terms excused it from delivering replacement power. However, PPL Montana did not provide information acceptable to NWE which verified that the second outage was a new, unrelated forced outage. After a period of three months, having not resolved the dispute with PPL Montana, NWE decided not to pursue the matter further because the cost of litigation could well exceed the disputed amount. NWE paid PPL Montana and included that cost in its 2004 annual default supply cost tracking filing. However, in paying PPL, NWE stated:

> "These types of events and possibly others (including support information supplied by PPL in this case) are included in NWE's annual default supply filings with the Montana Public Service Commission [Commission], as part of NWE's presentation, and, hence, we reserve the right to request further information and documentation if required."

125. Dr. Wilson testified that NWE made a diligent, good faith effort to identify the problem and recover the costs from PPL Montana and should not be penalized for PPL's non-delivery or PPL's refusal to compensate NWE for incremental cost of procuring replacement

energy. Given the possible precedent-setting nature of this event and PPL Montana's failure to provide fully acceptable verification of the alleged forced outage, Dr. Wilson suggested that the Commission consider ordering NWE to pursue this matter to a more satisfactory conclusion, including legal action, if warranted. The Commission should acknowledge that costs of implementing such an order are recoverable default supply costs.

126. Dr. Wilson stated that, with certain possible exceptions, there is an apparent commonality among many of the returning choice customers because they returned at approximately the same time. These customers were contemporaneously motivated to return to default supply service by market conditions, were primarily customers of the same retail supplier, CEM, and were directed back to default supply service, as a group, by CEM. Dr. Wilson maintained that it would be reasonable to assume that these choice customers reaped advantages from market supply service for some period of time. But once that advantage was reversed, these customers returned to default supply service potentially increasing costs to those customers who did not exercise choice or receive competitive market advantages.

127. Dr. Wilson stated that the Commission received several thoughtful comments in response to its June 8, 2004 Notice of Opportunity to Comment on issues related to the return of choice customers. Specifically, Large Customer Group commented that the law requires the Commission to simultaneously provide choice and protect small customers. NWE questioned whether incremental default supply costs and their causality could be measured with sufficient accuracy and suggested that as new supplies are procured incremental costs associated with returning choice customers would not likely persist. Given these thoughtful and plausible comments, along with the Commission's concurrent statutory obligations, the uncertain nature of default supply cost projections, and NWE's ability to carry forward a deferred cost balance for recovery in next year's tracker, when actual costs are known, Dr. Wilson recommended that the Commission find both the amount and cause of any potential incremental default supply cost related to returning choice customers is unknown and deal with the issue in the future. Alternatively, if the Commission finds that incremental costs of returning choice customers should be recovered in rates now, the Commission should implement a temporary surcharge for returning choice customers' rates with a provision for future credits if the projected incremental costs do not materialize.

**Response testimony**

**NorthWestern Energy**

128. Mr. Thomas filed testimony responding to testimony from MCC and AARP regarding NWE's proposals to expense DSM costs and include lost T&D revenues in the default supply cost tracker.

129. Mr. Thomas asserted that, after reviewing Dr. Wilson's testimony, NWE continues to find expensing preferable to capitalizing for several reasons. NWE does not own generating assets. All other default supply resources are 100% purchased and expensed. NWE remains concerned about the risk of regulatory assets created by capitalizing DSM. There is a quantity of DSM resource available at or below the cost of other alternative default supply resources; acquisition of this cost-effective DSM resource benefits customers financially. NWE's financial interests include timely recovery of its costs. Mr. Thomas asserted that aligning customer and utility interests is a good way to encourage aggressive and enthusiastic pursuit of DSM.

130. Mr. Thomas stated that the absence of a mechanism for recovering lost T&D revenues presents a clear disincentive to DSM acquisition. He asserted that MCC's and AARP's suggested approaches would result in non-recovery, or delayed recovery of expenses. This disincentive can, and should, be removed. Mr. Thomas stated that lost T&D revenues are part of the total cost of DSM and MCC's and AARP's approaches are equivalent to disallowing a portion of DSM costs.

131. Mr. Thomas testified that lost T&D revenues are different from other changes that occur between rate cases. In a business year that exactly matched test period parameters, i.e., load, weather, labor costs, taxes and other costs assumed when setting rates all match what actually occurs, NWE would still experience reduced transmission and distribution revenues from the conscious decision to implement DSM programs. He asserted it is not reasonable to conclude, as Dr. Wilson did, that lost T&D revenues are a legitimate offset to other gains from cost control, technology and/or load and sales growth.

132. Mr. Thomas disagreed with MCC and AARP that recovery of lost T&D revenues should be contingent on NWE demonstrating actual savings. He said in the field of DSM "actual savings" are like "precise estimates," an oxymoron. Although DSM program evaluations increase confidence in the estimates of energy savings, evaluation results necessarily rely on statistical analysis, assumptions and estimates. He asserted that the true, precise amount of

energy savings achieved by any DSM program operated by anyone anywhere is unknowable because the cost of such precise measurement is prohibitive or simply not possible. NWE cannot completely control the installation and use of measures, and cannot directly observe the production of energy savings. Sub-metering, data logging gear, communications technology and follow-up surveys are expensive and some customers consider them intrusive and annoying. As a result, DSM measurement and evaluation has been and will continue to be and imprecise science, according to Mr. Thomas.

133. Mr. Thomas said NWE's proposed lost revenue recovery approach allows for dynamic adjustments so if future program evaluations demonstrate that the lost revenue mechanism is overestimating savings, certain factors used in the calculation can be modified to reflect those results. One purpose of DSM program evaluation is to facilitate agreement on reasonable estimates of energy savings. But delaying lost revenue recovery until a post-program evaluation is complete only perpetuates the disincentive NWE's proposal is intended to remove.

134. Mr. Thomas responded to testimony from Ms. Alexander that the Commission should not authorize recovery of lost revenues at this time because NWE has not yet specified an evaluation methodology. He maintained that an unspecified evaluation methodology is not adequate justification for rejecting the Company's lost revenue recovery proposal. He referred to his direct testimony and the discussion of NWE's general plan for evaluating DSM programs presented there. He asserted that NWE will rely on outside contractors not involved with program implementation using standard evaluation methodologies. DSM evaluation has been performed for many years by utilities, the Northwest Power and Conservation Council, national laboratories such as Oak Ridge National Laboratory and numerous consulting firms, and there are several methods from which to choose. He said specifying an evaluation method should follow, not lead, DSM program design because appropriate evaluation techniques depend on how programs are designed and operated. He also said NWE will consult its advisory committee on an evaluation plan.

135. Reacting to Dr. Wilson's reference to Dr. Power's statement that the best DSM program for the utility under the proposed lost T&D revenue adjustment mechanism would be a program that does not work at all, Mr. Thomas stated that there is no basis to presume that NWE would attempt to trick the regulatory process into awarding it lost revenues. He said such behavior would be short-sighted and short-lived. Additionally, NWE does not object to using

post-program evaluations to true up lost revenue calculations, provided such true ups can capture under recovered amounts as well and return over collected amounts. Again, Mr. Thomas testified that removing the lost T&D revenue disincentive is a good way to encourage aggressive and enthusiastic pursuit of DSM.

**District XI Human Resource Council, Natural Resources Defense Council, Renewable Northwest Project**

136. Dr. Power filed testimony responding to MCC and AARP regarding DSM-induced lost T&D revenue recovery and expensing versus capitalizing DSM costs.

137. MCC argued that a lot of revenue-influencing factors change between rate cases and usually cause revenues to rise above the level rates were designed to produce. Dr. Power stated that this is not a convincing reason for rejecting NWE's proposed lost revenue recovery mechanism because NWE would receive those additional revenues between rate cases without DSM programs. NWE knows it will forego some of those revenues if it pursues DSM. If NWE does the right thing from a consumer perspective it reduces its profits; consumer interests and utility interests are not aligned.

138. Dr. Power disagreed with MCC that NWE has no real right to any increase in revenues tied to growth between rate cases and that the lost revenue adjustment only allows NWE to recover illegitimate windfall profit. According to Dr. Power, most regulators, including those in Montana, do not label as illegitimate revenue gains from growth or cost reductions between rate cases, and they do not attempt to confiscate such revenues. The lag between rate cases is part of a regulatory construct that tries to maintain a set of productive incentives for good business management. In this setting, there is a penalty for implementing effective DSM programs.

139. Dr. Power also disagreed with Dr. Wilson that the regulatory risk to NWE of not prudently procuring cost-effective DSM should override the disincentive created by lost revenues. According to Dr. Power, the combination of regulatory risks and lost revenues would present NWE with conflicting incentives and that would not be good regulation.

140. Dr. Power disputed Ms. Alexander's testimony that, in spite of commitments to DSM programs in Pacific Northwest states, lost revenue recovery mechanisms have not been adopted. Dr. Power referenced various current and past mechanisms adopted by regional public

utility commissions as well as current proceedings aimed at addressing the lost revenue disincentives. Dr. Power observed a renewed interest in the DSM lost revenue disincentive driven by volatile electricity prices associated with the California crisis in 2000-2001 and the rising cost of electricity, natural gas and other energy resources, which have reminded the region that energy efficiency can reduce the negative impacts of high and volatile energy prices. Additionally, Dr. Power asserted, following the deregulation boom of the 1990s it has become clear that utilities will continue to be electric supply portfolio managers for residential and small commercial customers.

141. Dr. Power stated that his clients do not uncritically accept NWE's proposed lost revenue adjustment mechanism. NRDC believes that a decoupling approach would provide more complete support for utility DSM programs than the lost revenue adjustment mechanism. But his clients support adopting NWE's proposal in this case for a trial period as a way of immediately dealing with NWE's concerns about lost T&D revenues. Part of their proposal involved exploring alternative ways of addressing the lost revenue disincentive over the next two years and presenting the Commission with the results.

142. In response to Ms. Alexander's testimony proposing a share the savings incentive to encourage DSM acquisition, Dr. Power reiterated that it is unlikely that any authorized incentive would overcome the disincentive of lost revenues. For example, at current rates NWE would lose 3.3 cents per kwh saved in the residential class. If the incremental cost of electricity were 5 cents per kwh and DSM cost 2 cents per kwh, the savings would be 3 cents per kwh. In this case, even giving NWE 100% of the savings would not overcome the lost revenue disincentive. Dr. Power concluded that the lost revenue problem has to be attacked directly. Positive incentives should be viewed as a complement to eliminating the lost revenue disincentive, not a substitute.

143. Responding to Dr. Wilson's concerns about the inequity of expensing DSM rather than capitalizing it, Dr. Power said this is only a conceptual problem in the early years of the DSM programs. Further, given the relatively small size of NWE's proposed DSM programs, the difference in rate impacts of one approach versus the other would be very small. Additionally, Dr. Power stated that conventional utility accounting practices do not usually levelize investments. Instead, capital recovery is usually front-end-loaded leading to higher revenue

requirements in early years that decline over the life of the asset. So having current customers pay more than future customers is a normal regulatory outcome, according to Dr. Power.

144. Dr. Power disagreed with Ms. Alexander's recommendation to delay a decision on a lost revenue recovery mechanism until NWE's 2006 rate case. To comply with the Commission's default supply resource planning and procurement rules NWE is expanding its DSM programs. NWE is incurring DSM costs now, and will continue to incur them between now and when the Commission ultimately issues an order on the 2006 rate case. Dr. Power asserted that NWE should not suffer losses for that period while it is carrying out the Commission's directives; to delay action on the DSM lost revenue disincentive would punish NWE for doing what the Commission asked it to do. Dr. Power maintained that this would not be a reasonable regulatory strategy.

## Commission Analysis, Findings and Decisions

### Lost T&D Revenue Adjustment

145. No party disputed that NWE will forego revenues it would otherwise receive between rate cases by acquiring cost-effective demand-side management resources (DSM). MCC and AARP opposed NWE's proposal for a lost transmission and distribution (T&D) revenue adjustment within the annual default supply cost tracking mechanism. However, Dr. Wilson acknowledged that some fixed T&D costs recovered in NWE's unit sales rates would be lost between rate cases if NWE acquires DSM. Data Request PSC-20, TR pg 11. Similarly, Ms. Alexander testified that lost T&D revenues are a legitimate issue. AARP-1, p 6. Dr. Power stated that effective DSM reduces utility revenues and profits relative to what they otherwise would have been without the DSM programs. District XI-1, p 11.

146. MCC objected to NWE's lost T&D revenue adjustment proposal on several grounds. Dr. Wilson stated that lost revenues in a given year would be speculative because they are based on the engineering estimates and statistical analyses of expert witnesses. He said other factors like load growth, changing incomes and growing use of electricity-using technologies would provide off-setting increases in revenues. And he asserted some T&D costs are variable, suggesting that in addition to reducing NWE's revenue, acquiring DSM would also reduce its costs.

147. MCC's objections, while relevant to the question of whether NWE's proposal is appropriate from an overall regulatory policy perspective, are not relevant to whether a financial disincentive to acquiring DSM derives from lost T&D revenues. Calculating lost T&D revenues in advance of program implementation and evaluation may be an imprecise science, but that is irrelevant to the question of whether utility revenue is affected by actual, effective DSM programs, which is the source of the financial disincentive. Similarly, the fact that load growth, abnormal weather, shifts in general economic conditions and changes in customer end-use behavior may increase revenue does not mean that the separable revenue impact of DSM ceases to exist. As Dr. Power pointed out, "[t]he reference point is what the revenues would have been if the utility had not engaged in DSM." District XI-1, p. 11. And finally, even if some T&D costs are variable in the near-term (i.e., between rate cases), a substantial portion of T&D costs remain fixed, regardless of sales volumes, as Dr. Wilson acknowledged. MCC-1, p. 17.

148. That there exists a real economic disincentive to utility acquisition of cost-effective DSM is not an issue in this proceeding. Rather, the issue is whether the Commission should do something to address that particular disincentive, and, if so, what and when.

149. MCC does not believe the Commission should do anything to address T&D revenue lost between rate cases due to DSM acquisition. Dr. Wilson stated that losing T&D revenues between rate cases would not likely affect NWE's acquisition of DSM because the Commission has adopted an open and transparent planning process which exposes NWE to financial risks if it fails to prudently acquire such resources. Data Request PSC-20, TR pg 11. In this regard, MCC questioned whether NWE is truly biased against DSM given the balance of economic incentives it faces. In addition, Dr. Wilson asserted that utilities are not entitled to all increased revenues that could occur between rate cases due to load growth and other factors and if it were practical to reset rates every day so that a utility recovered only prudently incurred costs plus a reasonable profit that would not be unfair. Id. MCC's initial brief disputed testimony by District XI that the opportunity to earn higher profits between rate cases is considered fair and reasonable and is an intentional part of the regulatory process which promotes good management. MCC also believes that adjusting revenues based only on DSM-related revenue changes, while ignoring factors that can cause offsetting revenue changes, would cause total revenue to diverge further from total cost of service than if no adjustment were made at all. MCC-1, p. 17.

150. Although AARP testified that lost T&D revenues are a legitimate issue, Ms. Alexander maintained that a distribution rate case such as the one NWE will file in 2006 is the appropriate forum for addressing ratemaking policies applicable to regulated distribution service rates. AARP-1, p. 6. In that context, she recommended that NWE be allowed to pursue a lost revenue adjustment, but only after the DSM programs have been evaluated and savings have been independently verified by a third party. She also suggested that the Commission evaluate alternatives to the lost revenue adjustment proposed by NWE, such as an incentive mechanism that allows NWE to keep a share of the net economic benefits of DSM programs.

151. Ultimately, the question of whether to adopt a lost T&D revenue adjustment is a question of regulatory stewardship. Given real economic disincentives to acquire resources that serve the public interest, and given the balance of other regulatory incentives NWE faces, would adopting the proposed lost T&D revenue adjustment contribute positively or negatively to achieving overall regulatory goals and objectives? Historically, concerns about lost revenues from DSM grew out of regulatory efforts to promote long-term, integrated resource planning by utilities. In turn, interest in integrated resource planning resulted from utility resource expansion plans that included costly new generating plants and the realization that there were vast, unexploited opportunities to increase energy efficiency at a lower cost. In requiring utilities to consider energy efficiency resources equally with conventional supply-side resources, regulators sought to encourage utilities to meet forecasted energy demand at the lowest, long-term total cost to ratepayers and society – promoting economic efficiency in the production and use of electricity is a fundamental justification for economic regulation of monopoly public utilities. See, for example, District XI Initial Brief, p. 4-5. Thus, according to the theory, achieving the goals of integrated resource planning (or achieving them efficiently) depends on aligning the financial interests of ratepayers, society and shareholders to the extent possible. Lost revenue adjustments attempt to do that. Lost revenue adjustment mechanisms are a regulatory reform designed to support integrated resource planning and should be evaluated in that context.

152. In its initial brief, MCC stated that the Commission "is understandably concerned with incentives for utility behavior, and it is appealing to think of 'aligning' all incentives. However, there is also a cost to these incentives." Initial Brief, p. 6. There are costs related to addressing the lost revenue disincentive. There are also costs to ratepayers and society of failing to achieve the goals of integrated resource planning. Montana's history provides a clear

example. This Commission embraced the concept of integrated resource planning in the early 1990's following a contentious period during which the Montana Power Company sought to rate base large investments in the Colstrip Units 3 and 4 power generating facilities, which the Commission determined were not needed to serve customer loads at the time and declined to include in customer rates. These events involved real and significant opportunity costs related to the allocation of society's resources.

153. As a result of the Colstrip experience Montana Power Company's Conservation and Least Cost Planning Advisory Committee (CLCPAC) was formed.[2] In October 1990, CLCPAC submitted its Integrated Least Cost Planning Report and Recommendations to the Montana Power Company and the Commission. That report noted that electric utilities have tended to choose new sources of supply over improvements in the efficiency with which customers use energy, that these new sources of supply are not least cost, and that these choices may reflect unproductive biases related to the particular market and regulatory environment in which utilities operate. The report cited several studies that identified a variety of ways that traditional rate of return regulation either conflicts with, or fails to mitigate market and institutional barriers to, integrated least cost planning and resource acquisition. The report recommended that the Commission consider the variety of regulatory reforms being proposed nation-wide to assure that the incentive structure in place in Montana supports and encourages integrated least cost planning and resource acquisition.

154. MCC asserted that there is speculation, but no proof, that the lost revenue disincentive will affect NWE's behavior in a way adverse to ratepayers to an extent that makes it worthwhile to implement a correcting adjustment. Data Request PSC-20, TR pg 11. The same is true of MCC's suggestion that the regulatory risks inherent in the resource planning and procurement process adequately counter the lost revenue disincentive. In fact, the Commission has no way of knowing which economic incentives will prevail as NWE's management weighs risks and opportunities on a daily basis. Further, the information asymmetry inherent in public utility regulation makes proving either case practically impossible. With respect to MCC's preferred approach, the Commission may not be able to perfectly detect all the subtle ways that DSM programs might have been prevented from achieving their full potential as the corporate

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[2] A 1988 settlement between MPC, District XI HRC and NRDC regarding legal challenges to the disposition of power from the Colstrip Unit 4 generating facility called for the creation of the Advisory Committee.

instinct to maximize profits filtered through multiple layers of management decision-making.[3] To the extent cost-effective DSM is not acquired or is acquired at a slower pace, total costs and risks for ratepayers and society will increase. Such considerations seem to be the point behind Dr. Power's testimony that over reliance by regulators on negative sanctions is not a reliable way, over the long-term, to motivate those who manage complex organizations like investor-owned utilities. District XI-2, p. 4. The Commission intends both to remove disincentives and assertively require NWE to assemble the most attractive integrated default supply portfolio, pursuant to its guidelines (ARM 38.5.8201-8226).

155. For the first time in almost ten years NWE has evaluated energy efficiency in terms of its relative cost-effectiveness as a resource to serve the needs of NWE's customers over the long-term. NWE determined in its 2004 default supply resource procurement plan that about 100 average megawatts of energy efficiency can be acquired cost-effectively within its system. Acquiring cost-effective DSM contributes to several of the Commission's default supply portfolio management and resource procurement goals and objectives. The average cost of energy efficiency is less than the current average cost of other portfolio resources and appears to be significantly less than current marginal costs of new supply-side resources. Therefore, acquiring energy efficiency mitigates upward pressure on long-term portfolio costs, as demonstrated in NWE's response to data request PSC-26. Cost-effective energy efficiency contributes to portfolio diversity, mitigates risk related to volatile fuel prices and wholesale electricity prices and is environmentally responsible, thereby mitigating risk related to future environmental regulation. For these reasons, and others, the Northwest Power and Conservation Council's Fifth Northwest Electric Power and Conservation Plan, released in May 2005, recommended aggressive acquisition of energy efficiency resources. Acquiring these cost-effective resources is in the public interest. District XI -1, p. 5.

156. Based on its evaluation of the record, the Commission finds that the lost revenue disincentive is real and puts at risk a full and complete ramp-up of cost-effective energy efficiency resource acquisition programs in the near-term.[4] Strong NWE support for energy

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[3] See Kahn, Volume II, Chapter 2 generally.

[4] In 1994, Lawrence Berkeley Laboratory analyzed the cost structures of 122 U.S. electric utilities and found that when prices are fixed and linear, there are very few situations in which increased (decreased) sales would not lead to increased (decreased) profits. See J. Eto, S. Soft and T. Belden, The Theory and Practice of Decoupling, January 1994. Most utility rate structures are not perfectly linear due to the existence of fixed monthly charges, demand charges, blocked rate designs, etc.

efficiency and other demand-side resources (e.g., rate design, demand response) is particularly important today given the recently demonstrated volatility of energy supplies and wholesale prices. Additionally, NWE is in the midst of planning for the acquisition of significant supply resources to replace existing supply contracts that expire in 2007. In light of the widely acknowledged disincentive tied to lost T&D revenue, the public interest value of DSM, and incomplete information on the existence and effectiveness of countervailing incentives, the Commission is not willing to risk creating lost opportunities with regard to NWE's acquisition of cost-effective efficiency resources.

157. The Commission finds that it is reasonable and in the public interest to implement, on an interim basis, NWE's proposed lost T&D revenue adjustment mechanism. The Commission approves, on an interim basis, NWE's request to recover $273,196 in estimated DSM program-related lost T&D revenue for the 2004-2005 default supply cost tracking period. This estimated lost T&D revenue amount must be trued-up based on actual program activity in 2004-2005 and again following a comprehensive program evaluation and independent verification of actual savings, which must be filed with the Commission no later than June 15, 2007. NWE must consult with its advisory committee on the selection of an independent contractor to evaluate DSM programs and the scope of work.

158. NWE is authorized to include estimated lost T&D revenue adjustments in annual default supply cost recovery filings for the 2005-2006 and 2006-2007 tracking years. NWE, in consultation with its advisory committee, must thoroughly evaluate the costs and benefits of the interim lost T&D revenue adjustment mechanism approved in this Order from Company, ratepayer and societal perspectives. Based on this evaluation, NWE must provide the Commission a report by June 15, 2007. The report may be incorporated into the Company's 2007 annual default supply cost recovery filing or a stand-alone filing. To the extent NWE wishes to continue the lost T&D revenue adjustment approach, the report must justify such a request in terms of the costs and benefits of that approach compared to other available methods for addressing the lost revenue disincentive, such as the various forms of decoupling, and a "do nothing" approach.

159. NWE's proposed lost T&D revenue adjustment proposal uses default supply rates to recover authorized lost revenues. Although the Commission questioned whether default supply rates were the appropriate rates with which to recover lost T&D revenue in data request PSC-

006, no intervenor discussed, either in testimony or in post hearing legal briefs, any policy or legal concerns with NWE's proposed approach. In its response to PSC-006, NWE maintained that lost revenues impact the T&D function of the utility because of a supply function – lost T&D revenues would not exist but for default supply resource procurement activities. NWE stated that it considered other methods for recovering lost T&D revenues but ultimately determined that, because default supply customers benefit most from the planned DSM activities they should pay a larger portion of lost revenues. Therefore, NWE believes using default supply rates is appropriate.

160. Although MCC opposed NWE's proposed lost T&D revenue adjustment, and AARP opposed Commission approval of the adjustment in this proceeding, their reasons did not involve policy or legal concerns with the appropriateness of using the default supply rate to effectuate any adjustment.

161. On an interim basis, the Commission approves NWE's proposal to recover lost T&D revenues through default supply rate adjustments. NWE made a plausible argument that from the Company's perspective lost T&D revenues represent an opportunity cost that is directly related to its procurement of electricity supply resources and the management of default electricity supply costs. However, the Commission intends to revisit this issue when NWE files its evaluation of the overall lost T&D revenue adjustment mechanism in June 2007. There may be legal and/or policy reasons to use other than default supply rates to recover lost revenues, to the extent a lost revenue adjustment of some kind will continue.

**Monthly default supply rate adjustments**

162. AARP recommended that the Commission end its current practice of adjusting default supply rates on a monthly basis in favor of annual rate adjustments. Ms. Alexander characterized this recommendation as a short-term option for providing NWE a stake in the management of the default supply portfolio, particularly with respect to stabilizing prices for residential and small commercial customers. AARP-1, p. 10. Ms. Alexander testified that annual default supply price changes would provide NWE an incentive to pursue longer-term fixed price contracts and rely less on short-term wholesale purchases. She also questioned NWE's view that residential consumption responds to monthly default supply price changes.

163. Given the volatility in wholesale electricity markets and the quantity of short-term market purchases used to meet default supply loads, NWE asserted that monthly default supply rate adjustments provide customers important, timely information about actual supply costs and market price trends which help them make informed consumption decisions. Mr. Thomas also testified that monthly rate adjustments reduce the balance in the electric default supply deferred cost account which, in turn, reduces interest charges related to the account. He said monthly rate adjustments are based on a rolling 12-month forecast of electricity supply costs, providing a degree of "smoothing" while still conveying timely price signals. According to Mr. Thomas, monthly default supply rate adjustments, by themselves, provide neither an incentive nor a disincentive with respect to NWE's efforts to control/stabilize default supply costs because the monthly adjustments are subject to final approval, after a prudence review, in annual filings.

164. The record suggests that changing from monthly default supply rate changes to annual changes will not materially affect residential customer bills, other things being equal. NWE's Late Filed Exhibit No.1 provides actual average monthly residential consumption for the period May, 2000 through July, 2005. An annual residential usage profile can be derived from this information by averaging each month in the data series. Using actual default supply prices for the period November, 2004 through October, 2005, bill variation with monthly default supply rate changes can be compared to bill variation using a fixed annual default supply rate. Table 1 contains the comparison.

**Table 1**

**Comparison of monthly and annual default supply rate changes**
**Average residential consumption**

| Month | Kwh | Default supply rate | Default supply bill | Monthly change | Average default supply rate | Bill at average rate | Monthly change |
|---|---|---|---|---|---|---|---|
| Jan | 937 | $ 0.04187 | $ 39.22 | | $ 0.04433 | $ 41.53 | |
| Feb | 795 | $ 0.04220 | $ 33.54 | -$5.68 | $ 0.04433 | $ 35.23 | -$6.30 |
| Mar | 751 | $ 0.04294 | $ 32.24 | -$1.30 | $ 0.04433 | $ 33.28 | -$1.95 |
| Apr | 673 | $ 0.04690 | $ 31.56 | -$0.68 | $ 0.04433 | $ 29.84 | -$3.45 |
| May | 599 | $ 0.04636 | $ 27.78 | -$3.78 | $ 0.04433 | $ 26.57 | -$3.27 |
| Jun | 591 | $ 0.04463 | $ 26.39 | -$1.39 | $ 0.04433 | $ 26.21 | -$0.35 |
| Jul | 652 | $ 0.04463 | $ 29.11 | $2.72 | $ 0.04433 | $ 28.92 | $2.70 |
| Aug | 676 | $ 0.04463 | $ 30.17 | $1.06 | $ 0.04433 | $ 29.97 | $1.05 |
| Sep | 623 | $ 0.04463 | $ 27.82 | -$2.35 | $ 0.04433 | $ 27.64 | -$2.33 |
| Oct | 584 | $ 0.04117 | $ 24.04 | -$3.78 | $ 0.04433 | $ 25.89 | -$1.75 |
| Nov | 663 | $ 0.04992 | $ 33.08 | $9.04 | $ 0.04433 | $ 29.37 | $3.48 |
| Dec | 836 | $ 0.04211 | $ 35.21 | $2.13 | $ 0.04433 | $ 37.06 | $7.69 |
| Total | 8,380 | | $ 370.17 | | | $ 371.52 | |
| Average | 698 | $ 0.04433 | $ 30.85 | | | $ 30.96 | |
| Standard Deviation | | $ 0.00252 | $ 4.18 | | | $ 4.86 | |

165. As shown in Table 1, monthly bills and month-to-month bill changes are virtually the same with and without monthly default supply rate changes. Seasonal weather changes affect monthly bills to a far greater extent than monthly default supply price changes. NWE offers a budget billing option for customers who wish to smooth out the affects of seasonal weather.

166. Residential demand for electricity is generally quite price inelastic in the short term. This elasticity tends to increase in the longer term. This Commission has long relied on marginal cost-based prices because prices for utility services that, where possible and equitable, convey relevant economic information are integral to achieving efficiency and the statutory standard of just and reasonable rates. A comprehensive analysis of rate design options, based on NWE's default supply cost of service, was not provided in this case. Arguably, as suggested by CEM witness Ron Perry, such an analysis is long overdue; the design of economically efficient and equitable default supply rates has not occurred since Montana Power Company's buy-back contract with PPL Montana expired in 2002. Nevertheless, given the current structure of NWE's default supply resource portfolio, cost and price volatility are to some degree an undeniable feature of default electricity service. Customers can avoid at least some of the effects of volatile supply costs and prices through energy efficiency improvements, obtained either by participating in an NWE program or their own initiative, as well as by other changes in their consumption behavior. Particularly in light of the small effects of monthly default supply price changes on residential customer bills, and the public interest benefits of cost-effective DSM acquisition (discussed in the previous section on lost T&D revenue), the Commission finds monthly default supply rate adjustments are reasonable. The Commission agrees with NWE that annual adjustments may increase interest costs and expose customers to larger, albeit less frequent, rate impacts, and that because the prudence of default supply costs are reviewed annually, monthly rate adjustments do not appear to impair existing regulatory incentives to control and stabilize costs.

**Corette Plant Outage in June 2004**

167. Dr. Wilson discussed a contract dispute between NWE and PPL Montana over whether an outage of the Corette plant in June 2004 was related to a scheduled plant outage,

which would require PPL Montana to provide replacement power at the contracted rate, or an unscheduled outage, which would require NWE to obtain replacement power at market rates.

168. NWE told PPL Montana that it was going to withhold $100,960 from its payments to cover its incremental supply costs. After a period of three months and after receiving copies of Generating Availability Data Systems (GADS) reports from PPL Montana, NWE decided not to pursue the matter further, finding that the cost of litigation could exceed the disputed amount. NWE paid PPL Montana and included the cost of the replacement power in its 2004 annual default supply tracker filing

169. Dr. Wilson testified that NWE made a diligent, good faith effort to identify the problem and recover the costs from PPL Montana and should not be penalized for PPL's non-delivery or PPL's refusal to compensate NWE for incremental costs of procuring replacement energy. Given the possible precedent setting nature of this event, Dr. Wilson suggested that the Commission order NWE to pursue this matter to a more satisfactory conclusion, including legal action, if warranted. Dr. Wilson noted that the Commission should acknowledge that costs from pursuing this issue would be recoverable default supply costs.

170. At the hearing Dr. Wilson recited his recommendation with respect to the Corette outage:

> "My recommendation is that this is also a matter of principle and a matter of precedent. And even if it costs the Company more than $100,000 to pursue this matter, I would recommend that the Commission consider authorizing, directing the company to do that and including the costs as recoverable, compensable default supply cost, even if the recovery is not made." (Tr. pg 130)

171. During the hearing Commissioner Schneider asked Dr. Wilson if there was any subsequent information which would indicate that the company had a higher likelihood of prevailing in this matter. Dr. Wilson replied that he didn't have any more information on the likelihood of winning.

172. The Commission agrees with Dr. Wilson that NWE made a good faith effort to investigate the Corette outage which took place in June 2004. After withholding payment of the $100,960 and then reviewing the GADS reports from PPL Montana, NWE determined that this matter was not worth pursuing and paid the disputed amount to PPL Montana. The Commission does not agree with Dr. Wilson's recommendation that the matter be pursued through litigation. The Commission accepts NWE's decision that the matter should not be further pursued in

litigation based on management's review of the likely cost of litigation and whether NWE would prevail on this issue.

173. Dr. Wilson expressed concern about whether or not further pursuing the Corette outage would somehow establish a bad precedent. The Commission in finding that this issue was properly managed by NWE establishes no precedent with respect to the prudent management of purchased power contracts. If in the future a power supplier does not perform under a contract with NWE, the Commission will require that NWE enforce the provisions of the contract in order to fully protect default supply customers. If there are problems with electric suppliers in the future, the Commission expects NWE to pursue appropriate remedies, including litigation to protect its customers.

**Stipulation on Qualifying Facility (QF) Replacement Energy**

174. On June 3, 2005 NorthWestern Energy (NWE) and the Montana Consumer Counsel (MCC) presented a proposed Stipulation Agreement which defined the methodology by which to prospectively treat QF replacement energy in electric trackers beginning July 1, 2005. A copy of the stipulation is appended to this Order as Attachment A.

175. In Order Nos. 5986w (Docket No. D97.7.90) and 6353c (Docket No. D2001.1.15), the Commission previously approved a stipulation that governs NWE's recoverable QF expenses for pre-restructuring QF supply resources. Pursuant to those Orders, NWE is obligated to provide a specified level of QF energy (809,002 MWh in this tracker period) at specified prices ($32.75/MWh in this tracker period). Appendix D of that stipulation contains QF volumes and costs through the 2031-2032 operating year. QF volumes decrease through time, while costs increase through time. NWE is responsible for replacing any QF supply shortfalls and is compensated at the agreed levels, regardless of actual cost.

176. In this proceeding, MCC and NWE had a disagreement about the appropriate methodology for determining the cost of makeup energy. NWE assigned to its QF replacement obligations lower cost purchases that MCC witness Dr. Wilson thought would more appropriately have been assigned to market purchases in the tracker cost calculation.

177. To resolve this issue, MCC and NWE entered into a stipulation agreement sponsored at the hearing by NWE witness Mark Thompson as NWE Exhibit No. 5. The stipulation specifies a "QF Replacement Energy Treatment Methodology" that does not attempt to assign

specific purchases to QF makeup or to general default supply. The cost assigned to QF makeup volumes in any year will be the lower of NWE's average annual short-term market purchases or the average mid-Columbia (mid-C) price for the year.

178. If one or more of the QF resources will experience an "Extended Outage" period NWE would have the right, but not the obligation, at the point an extended outage is determined, to prospectively procure replacement energy equivalent to the expected QF resource energy output (or remaining portion thereof) at a specific price for the same period as the outage (or remaining portion thereof). This energy would not be subject to the treatment identified in the paragraph above. Extended outage means any QF resource outage which NorthWestern can be reasonably sure will last more than ninety days and cause the minimum annual QF volume, not to be met. If NorthWestern elects to procure replacement energy for a QF extended outage, NorthWestern would, at the point an extended outage is determined, inform the MPSC and the MCC in a timely manner of the term, price and quantity of such energy. NorthWestern would place such extended outage replacement energy quantity in the tracker at a price level derived from the otherwise applicable QF generation sale stipulated rate.

179. As further consideration for this stipulation, NWE agreed to "complete its proposed Colstrip 4 default supply procurement as soon as practicable on the same terms as reflected in NWE's recently withdrawn preapproval filing, but excluding the QF makeup contingency incorporated in that filing."

180. Both MCC witness Dr. Wilson and NWE witness Mr. Thompson testified in support of the QF replacement energy stipulation. No parties in the dockets opposed the stipulation. The Commission finds that the QF replacement energy stipulation is in the public interest and approves the stipulation. The issue of the Colstrip 4 procurement needs to be clarified. It is not necessary that the form of procurement be a preapproval filing. Rather, NWE is directed to file with the MPSC a document within 10 days from the issuance of this Order indicating that the Colstrip 4 procurement has been completed pursuant to the agreement with the MCC.

**Stipulation on Returning Choice Customers**

181. On September 7, 2005 at the hearing NWE, the MCC and Commercial Energy presented a proposed Stipulation Agreement concerning treatment of returning choice customers. In June 2004, numerous choice customers of a single electricity supplier provided notice of their

intent to execute their right to return to default supply service on or about July 1, 2004. NWE calculated the impact of the cost to the electric default supply portfolio to be approximately $432,000, less than .2 percent of total default supply costs for the year. The stipulation proposed that a surcharge not be imposed on these customers upon their return to default supply. Mr. Corcoran for NWE, Dr. Wilson for MCC and Mr. Perry for Commercial Energy all testified in support of the stipulation. No party opposed the stipulation. A copy of the stipulation is appended to this Order as Attachment B.

182. The procedural history of this issue is described in Docket No. D2004.6.90, Interim Order No. 6574, Finding of Fact Nos. 3 to 7. In that Order, the Commission determined that incremental supply costs associated with returning customers should be included in rates for all customers. The Commission finds nothing in this record that causes it to revise that treatment of those costs. At the hearing Mr. Corcoran indicated that the language in NWE's Schedule No. ECCGP-1 (Electric Customers Choice Guidelines and Procedures), paragraph 8 is ambiguous. He noted that the language as it exists in the tariff is very confusing and hard to interpret. (Tr. P. 19) The Commission finds that the stipulation on returning choice customers is an acceptable resolution of this issue in these dockets. In accepting the stipulation the commission expressly rules that this stipulation does not establish precedent on the issue of returning choice customers in future proceedings. The resolution of this issue is strictly limited to the facts as they pertained to returning choice customers in these dockets.

**Capitalizing vs. Expensing Demand Side Management (DSM)**

183. NWE's witness Mr. Thomas stated that DSM costs should be treated the same way all other default supply portfolio costs are treated. Although capitalization has a lower cost in the early years of the program, it is more costly in the long-term because of the return component on the unamortized portion of the DSM investments. In addition, capitalizing DSM creates regulatory assets and the potential risk of future stranded costs.

184. AARP Montana chose not to take a position on this issue in these Dockets.

185. Dr. Power supported NWE's proposal to expense DSM investments in the year they are made. He noted that capitalizing DSM creates a "regulatory asset" where what supports the financing of the investment is the regulator's promise that the costs will be recoverable. Dr. Power asserted that it would be reasonable to treat DSM the same as other power purchases

which are expensed when incurred. Dr. Power also noted that the size of the planned DSM investments suggests that the impact on rates from expensing rather than capitalizing them would be quite small. Dr. Power also recommended that NWE track the source of funding for various programs and exclude from the default supply tracker, costs that are recovered through the USBC.

186. Dr. Wilson for the MCC recommended that DSM costs be capitalized. He stated that a better way to match program costs and program benefits over time is to capitalize DSM program costs. Under the capitalization approach, NWE's ratepayers would pay $14.8 million less during the first six DSM program years than they would if NWE were allowed to expense DSM program costs each year. Dr. Wilson found that appropriate because the main difference between expensing and capitalizing is that with expensing, ratepayers in the early years subsidize ratepayers in later years.

187. In his rebuttal testimony Mr. Thomas noted that after reviewing Dr. Wilson's testimony, NWE continues to prefer expensing to capitalizing. All other default supply resources are 100 percent purchased and expensed. NWE is concerned about the risk associated with creating regulatory assets by capitalizing DSM. There is a quantity of DSM resource available at or below the cost of other alternative default supply resources; acquisition of this cost-effective DSM resource benefits customers financially.

188. After reviewing the record in these Dockets on this issue the Commission finds that DSM investments should continue to be expensed in the year incurred. While true that DSM savings accrue over time, the Commission wishes to send a clear message to NWE that it should move forward aggressively to acquire the 100 megawatts of cost-effective DSM which it has identified in its planning. The cost of acquiring this resource is estimated to be $21 per MWH in nominal terms. The Commission finds that this resource is extremely cost-effective and further finds that the cost of acquiring this resource shall be treated exactly the same as any other resource acquisition made to serve the default supply. There is no doubt that this resource should be procured. Finally, the Commission finds that expensing DSM costs at the projected levels through the 2023-2024 operating year is not going to have a material impact on customer's rates. Given the modest impact on customer's rates, the Commission declines to create a regulatory asset for DSM costs.

189. NWE witness Mr. Markovich testified that NWE continues to rely on relatively short-term wholesale market purchases to supply approximately 30% of the portfolio's resource needs, and that this reliance on short-term purchases increases the risk profile of the portfolio. Exhibit NWE-1, p 12. NWE's contracts with PPL Montana, which provide nearly all the portfolio's baseload requirements and a large portion of heavy load requirements, expire in less than two years. Wholesale natural gas and electricity markets continue to display substantial price volatility. These issues are critically important to NWE's ability to provide adequate, reliable default supply service that is stably and reasonably priced in the near and long term. The Commission emphasizes the need for NWE to dedicate all available resources, both inside and outside the Company, to finding effective and creative solutions to these issues.

## Conclusions of Law

1. The Montana Public Service Commission (Commission) is invested with the full power of supervision, regulation and control of public utilities. § 69-3-102, MCA.

2. NorthWestern Energy (NWE) is a public utility subject to the jurisdiction of the Commission. § 69-3-101, MCA.

3. NWE is a distribution services provider and a default supplier of electricity. § 69-8-103, MCA.

4. The Commission has established an electricity cost recovery mechanism that obligates NWE to file annual Electric Default Supply Tracker filings. § 69-8-210, MCA.

5. NWE prudently incurred the electricity supply costs set forth in these jointly-administered dockets to provide default supply service during the 2002-2003 and 2003-2004 cost tracking periods. § 69-8-210, MCA.

6. Transmission and distribution revenue that is lost due to NWE's acquisition of demand-side resources is a demand-side management or energy efficiency cost. But for the acquisition of demand-side resource, NWE as the default supplier would not lose this revenue. The lost revenue is an actual cost of providing default supply service. NWE may include lost transmission and distribution revenue attributable to its acquisition of demand-side resources in electricity supply costs. § 69-8-103(13), MCA.

7. The Commission may authorize the recovery of lost transmission and distribution revenue on an interim basis subject to true-up and refund. § 69-3-304, MCA and § 69-8-210, MCA.

8. The allowance of recovery of lost transmission and distribution revenue on a temporary basis is necessary and convenient to ensure that NWE provides adequate and reliable default supply services at the lowest long-term total cost. § 69-3-103, MCA and § 69-8-419, MCA

9. Monthly default supply rate adjustments are consistent with the electricity cost recovery mechanism established by the Commission and are reasonable. § 69-8-210, MCA; *See* Docket D2003.6.77, Order No. 6496a (July 17, 2003).

10. NWE acted prudently in balancing the expected cost of litigation against the expected cost of recovery with respect to the dispute over the outage at the Corette plant in 2004 and in purchasing replacement power. § 69-8-210, MCA and § 69-3-106, MCA.

11. The Commission may approve stipulations that settle contested issues. § 2-4-603, MCA.

12. The Commission may determine the value of demand-side resources for rate-making purposes. § 69-3-109, MCA.

13. Any finding of fact that can properly be considered a conclusion of law and that should be considered as such to preserve the integrity of this Order is hereby incorporated as a conclusion of law.

## Order

1. The power supply expenses NorthWestern Energy incurred to provide default supply service in the 2002-2003 and 2003-2004 cost tracking periods were prudently incurred.

2. NorthWestern Energy's request to recover MPSC and MCC fees is approved on a final basis.

3. NorthWestern Energy is authorized to track and adjust default supply rates on a monthly basis to reflect actual expenses and rolling 12-month forecasts of default supply costs and loads.

4. NorthWestern Energy is authorized to expense investments in demand-side management programs in the year in which such costs are incurred.

5. The Stipulation Agreement between NorthWestern Energy and Montana Consumer Counsel regarding the Qualifying Facility Replacement Energy Treatment Methodology, included in this Order as Attachment A, is approved in its entirety.

6. NorthWestern Energy is directed to file with the Commission, a document within 10 days from the issuance of this Order indicating that the Colstrip 4 procurement has been completed pursuant to the agreement (Attachment A) with the Montana Consumer Counsel.

7. The Stipulation Agreement between NorthWestern Energy, Montana Consumer Counsel and Commercial Energy of Montana regarding the Returning Choice Customer issues, included in this Order as Attachment B, is approved in its entirety.

8. NorthWestern Energy is authorized to recover $273,196 in estimated lost transmission and distribution-related revenue from demand-side resource acquisition, on an interim basis, for the 2004-2005 tracking year. This estimate must be trued-up following a comprehensive program evaluation to verify savings.

9. NorthWestern Energy must file with the Commission on or before June 15, 2007, the results of a comprehensive evaluation, performed by an independent third party, of all demand-side management programs that verifies savings produced by the programs for the evaluation period. NorthWestern Energy must consult with its advisory committee on the selection of the independent evaluator and the proper scope of work.

10. NorthWestern Energy is authorized to include estimated lost transmission and distribution revenue adjustments in annual default supply cost recovery filings for the 2005-2006 and 2006-2007 tracking years.

11. NorthWestern Energy must, in consultation with its advisory committee, evaluate the costs and benefits of the lost transmission and distribution tracking and recovery mechanism the Commission temporarily approves in this Order from Company, ratepayer and societal perspectives. Based on this evaluation, on or before June 15, 2007, NorthWestern Energy must file a report with the Commission containing a recommendation for proceeding with either a continuation of the lost transmission and distribution mechanism, a modified or alternative mechanism, or no mechanism.

DONE IN OPEN SESSION at Helena, Montana on this 14th day of December 2005, by a 3-2 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

Greg Jergeson

Greg Jergeson, Chairman

Brad Molnar

Brad Molnar, Vice Chairman (dissent)

D. Mood

Doug Mood, Commissioner (dissent)

Robert H Raney

Robert H. Raney, Commissioner

Thomas J. Schneider, Commissioner

ATTEST:

Connie Jones

Connie Jones
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See ARM 38.2.4806.

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE MONTANA PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATIONS BY NORTHWESTERN ENERGY REGARDING ITS:<br><br>Electric Default Supply Filings for the tracking periods of November 1, 2002 through June 30, 2003 and July 1, 2003 25through June 30, 2004 | ) | UTILITY DIVISION<br><br>DOCKET NO.S D2003.6.77 and D2004.6.90 |

STIPULATION AGREEMENT BETWEEN NORTHWESTERN ENERGY AND THE MONTANA CONSUMER COUNSEL

COMES NOW NorthWestern Corporation, d/b/a NorthWestern Energy ("NorthWestern" or "NWE"), Applicant in the above entitled proceedings, and the Montana Consumer Counsel ("MCC"), collectively referred to as the "Parties", presenting a proposed Stipulation and Agreement to the Montana Public Service Commission (MPSC or Commission).

NWE and MCC, desire to enter into an agreement in these proceedings and to stipulate to the resolution of certain identified items. This Stipulation and Agreement is submitted to the Commission as a proposal to address the identified matters in the above Dockets.

## I. BACKGROUND

On June 16, 2003 and June 4, 2004, NorthWestern filed its Applications For Approval of its Electric Default Supply Costs for the tracking periods of July 1, 2002 through June 30, 2003 and July 1, 2003 through June 30, 2004 with the Commission. The MPSC issued Notices of Application and Notices of Opportunity to Intervene for both Dockets. Formal interventions were filed by the MCC and other interested parties, and allowed by the Commission.

## II. STIPULATION AND AGREEMENT

NorthWestern and the MCC agree as follows:

1. The MCC has intervened in these proceedings, reviewed prefiled testimony and exhibits and conducted discovery. The discovery process included review of all data requests and responses, an on-site discovery audit that was held at NWE's General Office in Butte, and several telephone conferences.

2. In reviewing Qualifying Facility (QF) replacement energy, the MCC identified the need to clearly define the methodology by which to prospectively treat QF replacement energy in electric trackers beginning July 1, 2005. Therefore, the Parties propose the following methodology:

<u>QF Replacement Energy Treatment Methodology</u>

<u>Background:</u>
Under a previous stipulation dated December 28, 2001, filed with and accepted by the Commission, associated with the sale of the former Montana Power Company electric generation assets, NWE is required to provide a fixed amount of QF electricity, at an agreed upon stream of fixed prices, independent of whether or not QFs operate at historical levels. Therefore, in those instances where QFs do not supply electricity at the contemplated levels, NWE is required to replace that electricity in conformance to the historical energy deliveries of the QF resource, or resources, for which the replacement power is required.

<u>Methodology:</u>
All required QF replacement energy would be treated as part of an electric default supply tracker using one of the two criteria stated below:

1. <u>Normal Performance Replacement Energy Criteria</u>
Normal QF Replacement Energy* shall be purchased as required throughout each tracking year and included in the tracker at its actual cost. The annual adjusted value of this replacement energy shall be determined by taking the annual replacement energy mWhs times the lower of i.) the Mid Columbia base-load (combination of On Peak and Off Peak) Dow Jones Index; or ii.) the average short-term market purchase price for the tracking year. Except for Extended Outage QF Replacement Energy, this dollar amount shall then be removed from annual tracking costs and replaced at a price level derived from the otherwise applicable QF Generation Sale Stipulated Rate**.

2. Extended Outage QF Replacement Energy Criteria
If it becomes known that one or more of the QF resources will experience an "Extended Outage" period, NorthWestern shall have the right, but not the obligation, at the point an Extended Outage is determined, to prospectively procure replacement energy equivalent to the expected QF resource energy output (or remaining portion thereof) at a specific price for the same period as the outage (or remaining portion thereof). Accordingly, this energy is not subject to the treatment identified in Item 1 above. Extended Outage shall mean any QF resource outage in which NorthWestern can reasonably be assured will last more than 90 days and cause the Minimum Annual QF Volume**, to not be met. If NorthWestern elects to procure replacement energy for a QF Extended Outage, NorthWestern shall, at the point an Extended Outage is determined, inform the MPSC and the MCC in a timely manner of the term, price and quantity of such energy. NorthWestern shall place such Extended Outage replacement energy quantity in the tracker at a price level derived from the otherwise applicable QF Generation Sale Stipulated Rate.

Defined Terms:
* Normal QF Replacement Energy - the amount of electricity purchased by NWE to fulfill the fixed amount of QF energy required if QFs do not perform at minimum annual Tier II volumes.
** QF Generation Sale Stipulation Rate - the volumes and/or rates contained in Appendix D – Annual QF Supply Volumes and Prices in MPSC Order 5986w.

3. The parties agree that NWE will complete its proposed Colstrip 4 default supply procurement as soon as practicable on the same terms as reflected in NWE's recently withdrawn prior approval filing, but excluding the QF makeup contingency incorporated in that filing.

4. The Parties agree that this Stipulation and Agreement should become effective as soon after approval by the Commission as is reasonably practical;

5. The execution of this Stipulation and Agreement shall not be deemed to constitute an acknowledgement by any Party hereto of the validity of any particular theory or ratemaking principle. Furthermore, no Party hereafter shall be deemed to be bound by any position asserted by any other Party, and no finding of fact or conclusion of law, other than those stated herein, shall be deemed to be implicit in this Stipulation and Agreement;

6. The entry of an Order approving this Stipulation and Agreement shall not be deemed to work any estoppel upon the Parties or the Commission, or to otherwise establish, or create, any limitation on or precedent of the Commission;

7. This Stipulation and Agreement shall not become effective and shall be of no force and effect until accepted and approved by the Commission as to all of its terms and conditions. If this Stipulation and Agreement is not approved, in its entirety or, if approved with conditions that are not acceptable to either Party, either Party shall, at its option, have the right to withdraw from this Stipulation and Agreement with all rights preserved;

8. The Parties hereto state that reaching agreement, as set forth herein by means of a negotiated settlement rather than a formal adversarial process, is in the public interest and that the compromises and settlements set forth in this Stipulation and Agreement are also in the public interest; and

9. This Stipulation and Agreement may be executed in one or more counterparts and each counterpart shall have the same force and effect as an original document and as if all the Parties had signed the same document. Any signature page of this Stipulation and Agreement may be detached from any counterpart of this Stipulation and Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of the Stipulation and Agreement identical in form hereto but having attached to it one or more signature page(s).

NOW, THEREFORE, based on the foregoing, NorthWestern and the Montana Consumer Counsel hereby request that the Commission issue an order granting NorthWestern approval of those items agreed to above.

Respectfully submitted this 31st day of May 2005,

NORTHWESTERN

Patrick R Corcoran

By: Patrick R. Corcoran
Vice-President Government and
Regulatory Affairs

MONTANA CONSUMER COUNSEL

Robert A Nelson

By: Robert Nelson
Montana Consumer Counsel

**ATTACHMENT B**

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE MONTANA PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATIONS BY NORTHWESTERN ENERGY REGARDING ITS:<br><br>Electric Default Supply Filings for the tracking periods of July 1, 2002 through June 30, 2003 and July 1, 2003 through June 30, 2004 | ) | UTILITY DIVISION<br><br>DOCKET NO D2003.6.77 and D2004.6.90 |

## STIPULATION AGREEMENT BETWEEN NORTHWESTERN ENERGY, THE MONTANA CONSUMER COUNSEL AND COMMERCIAL ENERGY OF MONTANA

COMES NOW NorthWestern Corporation, d/b/a NorthWestern Energy ("NorthWestern" or "NWE"), Applicant in the above entitled proceedings, the Montana Consumer Counsel ("MCC"), and Commercial Energy of Montana (CEM), collectively referred to as the "Parties", presenting a proposed Stipulation and Agreement to the Montana Public Service Commission (MPSC or Commission).

NWE, MCC and CEM desire to enter into an agreement in these proceedings and to stipulate to a resolution of the Returning Choice Customer issue and are submitting this stipulation to the Commission as a proposal to address this subject matter.

### I. Background

In June 2004, numerous choice customers provided notice of their intent to execute their right to return to default supply service on or about July 1, 2004. On June 17, 2004, upon Commission request, NWE filed an update to its tracker filing Docket No. D2004.6.90 to reflect the return of these customers. On July 8, 2004, the MPSC requested comments regarding whether returning choice customers (RCCs) should be assessed a supply rate designed to offset any incremental supply costs incurred by default supply customers as a result of such choice customers returning.

NWE filed comments and CEM filed testimony which stated that a surcharge was not warranted. CEM's testimony disputed whether the RCCs were definable as a group, the administrative burden of tracking such an event, and the net rate impact of their return to default supply.

The Commission's Interim Order did not include a surcharge.

## II. Agreement and Stipulation

1. NWE has estimated the costs of providing electricity to the RCCs for the 2004 – 2005 tracker year. That analysis is attached and estimates the total additional costs as $432,309, less than 0.2% of total default supply costs for the year. Given the reasons stated in comments and testimony filed by the undersigned parties, as well as the minimal impact, the parties agree that no surcharge should be imposed on the choice customers returning during the tracker period.

2. The Parties agree that this Stipulation and Agreement should become effective upon issuance of a final order in Docket No. D2004.6.90;

3. The execution of this Stipulation and Agreement shall not be deemed to constitute an acknowledgement by any Party hereto of the validity of any particular theory or ratemaking principle. Furthermore, no Party hereafter shall be deemed to be bound by any position asserted by any other Party, and no finding of fact or conclusion of law, other than those stated herein, shall be deemed to be implicit in this Stipulation and Agreement;

4. The entry of an Order approving this Stipulation and Agreement shall not be deemed to work any estoppel upon the Parties or the Commission, or to otherwise establish, or create, any limitation on or precedent of the Commission;

5. This Stipulation and Agreement shall not become effective and shall be of no force and effect until accepted and approved by the Commission as to all of its terms and conditions. If this Stipulation and Agreement is not approved, in its entirety or, if approved with conditions that are not acceptable to any Party. Any Party shall, at its option, have the right to withdraw from this Stipulation and Agreement with all rights preserved;

6. The Parties hereto state that reaching agreement, as set forth herein by means of a negotiated settlement rather than a formal adversarial process, is in the public interest and that the compromises and settlements set forth in this Stipulation and Agreement are also in the public interest; and

7. This Stipulation and Agreement may be executed in one or more counterparts and each counterpart shall have the same force and effect as an original document and as if all the Parties had signed the same document. Any signature page of this Stipulation and Agreement may be detached from any counterpart of this Stipulation and Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of the

Stipulation and Agreement identical in form hereto but having attached to it one or more signature page(s).

NOW, THEREFORE, based on the foregoing, NorthWestern Energy, the Montana Consumer Counsel and Commercial Energy hereby request that the Commission's final order in this docket reflect no surcharge be imposed on choice customers during this tracker period.

Respectfully submitted this 7th day of September 2005,

NORTHWESTERN ENERGY

Patrick R Corcoran

By: Patrick R. Corcoran
Vice-President Government and
Regulatory Affairs

MONTANA CONSUMER COUNSEL

Robert Nelson

By: Robert Nelson
Montana Consumer Counsel

COMMERCIAL ENERGY OF MONTANA

Ron Perry

By: Ron Perry
CEO and President

NorthWestern Energy
Analysis of Returning Choice Loads
Default Supply Cost Impact

| | Jul-04 | Aug-04 | Sep-04 | Oct-04 | Nov-04 | Dec-04 | Jan-05 | Feb-05 | Mar-05 | Apr-05 | May-05 | Jun-05 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Initial Analysis*** | | | | | | | | | | | | | |
| Without Returning Choice Load: | | | | | | | | | | | | | |
| Total Mwh load | 525,519 | 504,050 | 437,905 | 458,801 | 487,360 | 529,575 | 537,120 | 477,794 | 494,551 | 436,634 | 440,196 | 459,401 | 5,788,90 |
| Total Default Supply Cost | $ 20,730,754 | $ 19,316,240 | $ 15,571,826 | $ 17,107,290 | $ 18,885,921 | $ 20,854,647 | $ 21,555,274 | $ 19,006,198 | $ 19,188,704 | $15,016,310 | $14,651,506 | $15,134,210 | $ 217,018,88 |
| Cost per mwh | 39.45 | 38.32 | 35.56 | 37.29 | 38.75 | 39.38 | 40.13 | 39.78 | 38.80 | 34.39 | 33.28 | 32.94 | 37.4 |
| With Returning Choice Load: | | | | | | | | | | | | | |
| Total Mwh load | 545,600 | 523,915 | 455,285 | 476,559 | 505,004 | 548,149 | 556,065 | 494,756 | 512,876 | 453,502 | 457,469 | 477,063 | 6,006,24 |
| Total Default Supply Cost | $ 21,924,991 | $ 20,498,550 | $ 16,606,409 | $ 18,062,648 | $ 19,838,134 | $ 21,857,999 | $ 22,594,878 | $ 19,938,123 | $ 20,195,822 | $15,601,550 | $15,156,429 | $15,650,842 | $ 227,926,37 |
| Cost per mwh | 40.19 | 39.13 | 36.47 | 37.90 | 39.28 | 39.88 | 40.63 | 40.30 | 39.38 | 34.40 | 33.13 | 32.81 | 37.9 |
| Returning Choice Load only: | | | | | | | | | | | | | |
| Total Mwh load | 20,081 | 19,865 | 17,380 | 17,758 | 17,644 | 18,574 | 18,945 | 16,962 | 18,325 | 16,868 | 17,273 | 17,662 | 217,33 |
| Total Default Supply Cost | $ 1,194,237 | $ 1,182,310 | $ 1,034,583 | $ 955,358 | $ 952,213 | $ 1,003,352 | $ 1,039,604 | $ 931,925 | $ 1,007,118 | $ 585,240 | $ 504,923 | $ 516,632 | $ 10,907,49 |
| Cost per mwh | 59.47 | 59.52 | 59.53 | 53.80 | 53.97 | 54.02 | 54.87 | 54.94 | 54.96 | 34.70 | 29.23 | 29.25 | 50.1 |
| Incremental paid by Other DS Cust: | $ 387,280 | $ 405,078 | $ 400,652 | $ 282,290 | $ 259,102 | $ 262,695 | $ 269,802 | $ 248,375 | $ 285,524 | $ 4,941 | $ (67,350) | $ (62,799) | $ 2,675,56 |

*Data Source: Kevin Markovich worksheet

| | Jul-04 | Aug-04 | Sep-04 | Oct-04 | Nov-04 | Dec-04 | Jan-05 | Feb-05 | Mar-05 | Apr-05 | May-05 | Jun-05 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Jul04-Jun05 Actuals:** | | | | | | | | | | | | | |
| [1] Without Returning Choice Load: | | | | | | | | | | | | | |
| Total Mwh load | 437,415 | 466,816 | 426,269 | 395,512 | 403,837 | 478,722 | 543,884 | 470,836 | 433,021 | 423,577 | 400,719 | 412,823 | 5,293,43 |
| Total Default Supply Cost | $ 19,920,796 | $ 17,915,820 | $ 14,424,307 | $ 16,144,642 | $ 17,594,873 | $ 20,737,207 | $ 21,795,853 | $ 18,331,429 | $ 18,933,186 | $16,952,347 | $15,287,359 | $16,768,206 | $ 214,806,02 |
| Cost per mwh** | 45.54 | 38.38 | 33.84 | 40.82 | 43.57 | 43.32 | 40.07 | 38.93 | 43.72 | 40.02 | 38.15 | 40.62 | 40.5 |
| [2] With Returning Choice Load: | | | | | | | | | | | | | |
| Total Mwh load | 450,573 | 482,228 | 440,552 | 409,127 | 417,269 | 492,096 | 557,139 | 483,481 | 445,362 | 436,121 | 413,631 | 426,230 | 5,453,80 |
| Actual Default Supply Cost | $ 20,510,103 | $ 18,564,824 | $ 14,890,419 | $ 16,698,960 | $ 18,204,924 | $ 21,442,069 | $ 22,440,514 | $ 18,892,287 | $ 19,560,480 | $17,606,860 | $15,673,866 | $17,291,374 | $ 221,746,67 |
| Cost per mwh | 45.52 | 38.50 | 33.80 | 40.82 | 43.63 | 43.51 | 40.28 | 39.08 | 43.92 | 40.37 | 37.89 | 40.57 | 40.6 |
| Returning Choice Load only: | | | | | | | | | | | | | |
| [3] Total Mwh load | 13,158 | 15,412 | 14,283 | 13,615 | 13,432 | 13,374 | 13,255 | 12,645 | 12,341 | 12,544 | 12,912 | 13,407 | 160,37 |
| Total Default Supply Cost | $ 589,307 | $ 649,003 | $ 466,111 | $ 554,318 | $ 610,050 | $ 674,861 | $ 644,661 | $ 560,858 | $ 627,293 | $ 654,513 | $ 386,507 | $ 523,167 | $ 6,940,65 |
| NWE Actual Term Purchases | 44.79 | 42.11 | 32.63 | 40.71 | 45.42 | 50.46 | 48.64 | 44.35 | 50.83 | 52.18 | 29.93 | 39.02 | 43.2 |
| Incremental paid by Other DS Cust: | $ (9,667) | $ 55,676 | $ (16,641) | $ (1,379) | $ 24,046 | $ 92,922 | $ 110,776 | $ 66,743 | $ 85,256 | $ 148,080 | $ (102,783) | $ (20,719) | $ 432,30 |

*Calculated using initial analysis increment

[1] Calculated
[2] Source: 2005 Actual Data
[3] Source: Billing data

CERTIFICATE OF SERVICE

I hereby certify that a copy of a **FINAL ORDER NO. 6496f** issued in D2003.6.77 in the matter of NorthWestern Energy Electric Default Supply Tracker Filing has today been served on all parties listed on the Commission's most recent service list, updated 6/8/05, by mailing a copy thereof to each party by first class mail, postage prepaid.

Date: December 16, 2005

*Donna Turkowski*
For The Commission

Intervenors:

AARP
Commercial Energy of Montana
District XI Human Resource Council
Federal Executive Agencies
Large Customer Group
Montana Consumer Counsel
Natural Resources Defense Council
NorthWest Power and Conservation Council
Renewable Northwest Project